SMALL HYDRO

’88

An International Conference and Trade Show

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PLENARY SESSION

Chairperson: R. Paul Shervill
Ministry of Energy

Welcome

By
Honourable Robert C. Wong
Minister of Energy

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NOTES FOR CONFERENCE OPENING BY

THE HONOURABLE ROBERT C. WONG
ONTARIO MINISTER OF ENERGY

FOR THE

SMALL HYDRO '88 CONFERENCE

WEDNESDAY, JULY 6, 1988
8:30 A.M.

Good morning, and welcome to Small Hydro '88. I hope most of you will have had a chance to get the feel of Toronto. Perhaps some of you have already discovered the excellent restaurants. If you haven't yet, I can promise that you will -- Toronto has hundreds of them.

But now it's time to get down to work, isn't it? I don't mind telling you all that I am very proud to be here today, and anxious to kick-start the coming series of exhibits and discussions on small scale hydro power.

This trade show and conference has been a pet project of ours at the Ontario Ministry of Energy, in co-operation with several international development agencies, and I am delighted to see it get underway. We have been planning this carefully for over two years, to make sure that you all have a fully-packed and productive time here.

I want you to know that it is especially gratifying for me, as a provincial cabinet minister, to see how Ontario can draw people from all over the world to sample our expertise.

We knew, from the moment the conference idea came out of its cocoon, that it would draw a crowd. But the response to our initial advertisements was a surprise, notwithstanding. We received a blizzard of 1,500 enquiries from some 97 countries.

In fact, the response was so big that one member of my staff started collecting stamps from the letters that poured in, just for fun. That international stamp collection is now quite an impressive thing to behold, let me tell you.

France, China, Iran, the United States, Pakistan, Argentina, and dozens of other countries are represented in the stamp collection, as they are here in the flesh.

We welcome you all to Ontario, which has economic and cultural ties to all of those places. And as the province's Minister of Energy, I can assure you of something: You have come to the right place.

My province is very rich in hydroelectric potential, and in the knowledge of its use. Our development of hydro power began many decades ago with small scale sites. So we have already been where many of you are now preparing to tread -- building hydroelectric sites on a small scale that must function in extreme climates, and often in remote locations. We know this territory.

Our early experience stood us in good stead as we developed our own hydro potential into the megaprojects that still dominate it. In more recent times, however, we have discovered a renewed need to develop the smaller sites.

Ontario has over 30,000 lakes and rivers with many usable small hydro sites, and as our need for energy efficiency rises in the 1980s, we are coming to realize that we can no longer afford to let them lie fallow.

So you can see that Ontario has a substantial interest in small hydro for itself, too, right now. Yet because of our history with it, we know a good deal about how it can be a problem-solver in many of the places you people hail from.

Tomorrow I will speak in more detail on where Ontario is in hydro power, and how we got to where we are. My point now is simply that we have a wealth of experience to share. Nor is Ontario's the only experience that's here to share. Some of the experience available at the conference is like Ontario's cultural mixture -- imported.

Most of the week will be technical sessions, as you know. But this morning is a plenary session, and besides myself, we have lined up several heavy hitters in the field of small hydro, to speak to you.

We will hear from Nicky Beredjick, of the United Nations' department of international co-operation for development. He will discuss U.N. programs in small hydro.

Peter Haines, vice-president of the professional services branch of CIDA -- the Canadian International Development Agency -- will discuss CIDA's programs in small hydro.

We will also hear from Robert Franklin, president of Ontario Hydro. That company is one of the biggest corporations in this country, and has huge expertise in hydroelectric installations both large and small.

We will hear from Jeff Passmore, president of Passmore Associates International. He is an Ottawa-based consultant who will speak on global markets for small hydro.

As you can see, our featured speakers represent both the Ontario view and the world view; both the voice of practical experience and that of academic expertise.

The same things may be said of the technical sessions that make up the meat of the week's activities. They represent a varied and, we believe, complete menu of subjects. You will have the opportunity to pick and choose from a smorgasbord of discussion topics.

For those interested in the nuts and bolts of the engineering for small hydro, there are sessions on the design of the turbomachines, and on designing machinery for winter conditions -- something we know a bit about in this province, despite the July weather here now.

For those interested in the nuts and bolts of management that comes before, during and after the engineering, we've scheduled sessions covering such topics as dam insurance, and Canadian utilities' policies covering private generation.

Hydro installations, large or small, cost money. So there are sessions on world bank experience financing small hydro in Malaysia and in India.

Some of the other session topics include plant rehabilitation, and a look at hydro stations on man-made canals in Pakistan. And there are several sessions covering various aspects of the environmental, social and legal impact of hydroelectric stations.

It is indeed a varied range of topics that we have assembled for you, encompassing much of Ontario's rich experience in the field, plus world experience. I am confident that you will find the kind of cross-pollination of ideas that you came here for, among the various sessions.

And as I said once before, I am also confident that, in addition to the useful work you can accomplish while here in Toronto, you can also have a lot of fun.

This trip is supposed to be a working holiday, after all. So enjoy the sights and sounds of Ontario, along with the sessions and the exhibits that make up the working part.

Then, perhaps, we can look forward to seeing some of you return in the future, just for the holiday part of it.

Ladies and gentlemen: Have a very productive conference.

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The United Nations Programme for Establishing Small-Scale Hydro Power Projects in Developing Countries

By
Dr. Edmund K. Leo
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SMALL HYDRO 88

THE UNITED NATIONS PROGRAMME FOR ESTABLISHING SMALL-SCALE HYDROPOWER PROJECTS IN DEVELOPING COUNTRIES

Statement of Dr. Edmund K. Leo
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UNITED NATIONS

Presented at the Small Hydro 88
An International Hydropower Conference held at Toronto
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THE UNITED NATIONS PROGRAMME FOR ESTABLISHING SMALL-SCALE HYDRPOWER PROJECTS IN DEVELOPING COUNTRIES

General Objectives

Developing countries generally suffer from a wide divergence in their economic structure between central and outlying areas. This results in low country-wide per capita averages of domestic product and energy consumption caused by the no more than subsistence level often found away from a few economically more advanced urban centres. There is a pressing need to introduce greater social and economic homogeneity by promoting development in the outlying areas. An ample supply of energy is the key for this process. It will permit overcoming the inhibiting features of a subsistence economy which tend to stifle progress; it also fosters social, commercial and industrial activity, initially only in the immediately affected areas but ultimately in the country as a whole.

Many countries have recognized that something needs to be done to improve the energy supply in rural and outlying areas but they have often lacked the means for taking action. Small diesel stations were set up in a few isolated places, principally to supply electricity to small communities or agricultural and industrial establishments, but the costs of small-scale and disaggregated diesel generation are high, operational and maintenance problems can be troublesome and the dependence on a premium fuel, usually imported and expensive to bring to the site, is burdensome for the national economy; it can be almost prohibitive for the local economy if it is not subsidized. There is therefore a clear need for more extensive exploitation of indigenous energy resources which cannot only replace diesel generation but can also offer a more ample supply of cheap energy for remote localities.

For the majority of developing countries with large populations residing in remote rural areas, the availability of reliable, low cost energy supplies is essential to the realization of the economic and social development goals for their nationals.

The United Nations is in a unique position to assist developing countries in this field. The United Nations Department of Technical Co-operation for Development (DTCD) - has been entrusted with this mandate to assist Governments in exploration and exploitation of their natural resources and energy endowments, in accordance with their national objectives and priorities. This mandate received fresh impetus from the Nairobi Plan of Action adopted by the United Nations Conference on New and Renewable Sources of Energy in 1981 which underscored the importance of bringing special programmes aimed at improving the supply of indigenous energy to rural and outlying areas in developing countries. In this effort given the availability of extensive largely untapped hydropower resources in many countries hydropower development has become a major focus of international efforts to provide energy to remote rural areas.

Small river courses suitable for hydropower generation can be found in many parts of the world, even in countries not well endowed with water resources. The size and dispersed location of such rivers has impeded their exploitation but perhaps the greatest restraining influence has been due to a lack of resources - both technical and financial - in the countries concerned. This has prevented them from embarking on the development of potentially promising schemes. Authorities in the developing countries tend to have their efforts absorbed by the energy supply problems of the central and urban areas which must therefore assume greater priority in the national development plan. Small and dispersed hydro resources then tended to be left unexplored and unexploited.

Electricity offers the most convenient and versatile energy form where basic services - for light, heat and power - are provided from a central source. Every scenario aiming at an improved supply of energy must accord priority to the electrification of new areas as well as extend electricity to areas already benefitting from a basic supply. It is in this sphere that the United Nations system can target specifically the promotion of small-scale electrification in hitherto inadequately supplied areas, on the premise that such action could have an immediate beneficial impact on the social and economic situation of the rural populations concerned. Because of the widespread - although by no means universal - availability of small-scale hydropower resources and because of the likelihood that their exploitation could make an immediate contribution to an unsatisfied energy market, the United Nations Department of Technical Co-operation for Development initiated in 1980 a world-wide programme for identifying and reviewing the scope for small-scale hydropower in developing countries. The overall objective of the programme has been to assist the authorities concerned - governments or para-statal utilities - in the review and assessment of potential sites or schemes which previous surveys had found to be promising or which warranted further investigation, with the ultimate aim of transforming those considered potentially viable into energy producing small hydropower facilities. Criteria for success were defined by the technical and economic feasibility of given proposals and their scope for attracting investment funds for implementation.

The objective of the Department's survey programme was to identify technically and economically feasible projects which would be suitable for supplying electricity to isolated areas. Many such areas have been hitherto provided with electricity from local diesel stations at very high cost and a special feature of the survey programme was therefore to identify situations in which the costs of supply could be materially reduced in both real terms and through shadow pricing by the substitution of hydropower for diesel power based in most cases on imported oil.

The survey programme has now embraced 41 developing countries and has shown that there is ample opportunity for energy substitution. The terms of reference for the survey programme were phased to concentrate on small-scale power schemes in the range of 500 kW to 5 MW rather than on micro schemes. Micro schemes can also in many cases offer possibilities of energy substitution but their appraisal requires a different kind of effort supported primarily by local resources; it cannot satisfactorily be undertaken by short-term survey missions of the kind fielded under this programme.

This global survey programme, which will eventually embrace 55 countries, is part of the Department's efforts to promote new and renewable sources of energy as well as accelerate the rate of import substitution in the energy sector in developing countries. With its focus on providing electric power to isolated rural communities, the survey provides an opportunity for the developing countries to enhance their resource availability which is a pre-requisite in their socio-economic transformation.

Programme Parameter

A programme designed to cover a wide range of countries differing in climatic and ambient conditions, in their institutional structure and their socio-economic development must have sufficient universality to deal with the range of circumstances to be met; it would not be possible to set up a separate programme for every country. In order to maintain a universality of approach, the Department set out clear guidelines which satisfied the needs of the project and ensured that a sufficiently comprehensive and uniform product was obtained. Uniformity of approach was essential for monitoring the work and appraising the results and also for arranging governmental follow-up in appropriate cases.

Within the context of this programme, "small-scale" was defined as a size range of broadly 500 kW to 5 MW. Schemes falling slightly outside this range were not excluded from consideration, especially as it was often not known to what capacity a given proposal could be developed; such information did not become available until the project work was well advanced. The view was held, however, that micro schemes of substantially less than 500 kW capacity require a different approach. The cost of developing such schemes was considered to be too great to be economically justified unless a number of sites or schemes could be grouped into a single project.

Selection of schemes for evaluation under the programme was always left to the authorities concerned. They were advised:

- that the schemes should be sited in an area where sufficient survey work has already been done to confirm that an exploitable hydropower potential does in fact exist;

- that there needs to be a market for the electricity to be produced, either in replacement or expansion of existing diesel generation or for new consumers hitherto without a supply;
- that the number of schemes to be evaluated should be limited to the most promising and urgent cases so that they could be fitted into the short timeframe available for the survey mission;
- that a uniform approach was essential for effective project management but that special requirements, such as advice on refurbishment of existing plants, on the preparation of a hydropower inventory or on the setting-up of training courses would be examined with a view to identifying future technical co-operation programmes in these areas that could be supported by the United Nations, other multi-lateral or bilateral aid agencies.

Survey team were then sent to the countries concerned with the Governments providing available information on the power supply situation in general and on the prospects for small-scale hydropower in particular, including all the studies already carried out on potentially promising sites.

It was decided to make the programme available to as many countries as possible but funding limitations made it necessary to restrict each survey mission to about one month. This meant that, on average, 3 to 4 schemes could be examined in some detail. The economy and electricity supply situation as a whole was reviewed in general terms in each of the countries visited by the survey missions. The general information was intended to help in putting the small-scale programme into a national focus. The overall objective of the approach was to identify situations where demonstration schemes could be set up which might then form focal points for further national and regional dvelopment of small-scale hydropower.

Funding limitations also made it necessary to limit the size of the expert team sent to each country and to include only those disciplines which were essential for a first appraisal. Experience with in-depth country projects had shown that the survey work could be adequately covered with a team of two experts with sufficient breadth of experience to deal with a range of subjects at the pre-feasibility level. The teams selected comprised the following personnel:

- a civil engineer-hydrologist who would examine the site parameters, with emphasis on the hydrology, prepare an outline design and a cost estimate for the civil engineering component and establish the required cash flow in local and foreign expenditure;
- a hydropower engineer who would appraise the power market, co-operate with the civil engineer in determining the capacity to be installed in the scheme, estimate the cost and the cash flow for the electro-mechanical component and also for the transmission link to the load centre or the point of supply in an existing network.

One of the engineers was expected to prepare an assessment of economic merit and also review the general situation in the country concerned. Both engineers were to collaborate in preparing general recommendations for further action or at least comment in detail on their findings. In one or two cases, where the hydrology was known to be difficult, the function of civil engineer and hydrologist was split and a team of 3 members then entrusted with the survey. This made it possible to offer governments more extensive guidance on the formulation of hydrological programmes which were a pre-condition for the introduction of small-scale hydropower.

The senior member of each survey team was briefed at United Nations Headquarters before embarking on a mission to ensure proper compliance with the terms of reference and secure a uniform product from each mission. The terms of reference covered the job descriptions described above but the approach to be adopted and the general objectives to aim for were discussed at the briefing. The briefing also brought out any problems the team might have in dealing with the wide range of matters to be covered, the short time span available for the survey in the field and the proper targeting of the exercise towards concrete objectives. Advice was frequently needed on the economic evaluation of particular schemes; there appeared to be a lack of experience with this subject even though the information asked for was no different from that commonly required by bilateral and multilateral aid and financing agencies. Experts were selected for their familarity with developing country conditions and guidance on this topic was generally not needed. In some cases, the survey work had brought out difficulties arising mainly from conflicting information or institutional problems and a debriefing at Headquarters was then arranged so that the views of the various parties involved - governments, survey teams and Headquarters staff - could be reconciled before the mission report was prepared. This report was intended to make a positive contribution towards the development of small-scale hydropower in the countries visited by the team and point to one or two schemes, wherever possible, with sufficient promise to permit immediate implementation provided adequate technical and financial support could be given to the responsible authority. The report was also expected to give governments a general appraisal of the prospects for small-scale hydropower in rural and remote areas and to suggest to them further work which might be undertaken in cases where a single scheme of adequate promise had not been identified.

Technical Considerations

The key issues which the programme was intended to explore for specific localities were the following:

1. The existence of an adequate power market formed by
    - substitution for diesel-generated energy,
    - a new supply to new consumers,
    - an expanding demand in an existing network,

    or a combination of these factors.
2. Satisfactory hydrological conditions which would ensure sufficient water availability for a reasonable power production pattern throughout the year, a requirement which could not be met in many cases.
3. Suitable topography and sub-soil conditions which would permit an economic design to be developed.
4. Ready access to the site both for construction and for subsequent operation.
5. Reasonable distances from the load centre or from the power infeed point in an existing network supplied from the scheme.

6. Adequate scope for local participation in construction through the supply of labour, materials for construction and also manufactured items in suitable cases.
7. An acceptable economic merit which could support a decision in favour of implementation.
8. An institutional framework which would secure proper supervision and management of the development and construction activity and would ensure satisfactory operation of the scheme.

The survey programme has brought out particular problems for these issues which it may be instructive to review.

1. Power Market

Electricity utilization levels depend greatly on local circumstances and the power market presenting itself to a particular scheme under review must therefore be established in every case, as well as the growth potential of this market. The market that can be supplied will be restricted by the capacity to which the scheme can be developed, the variations in hydropower production throughout the year and the transmission distances from the plant to the load. The market appraisal must be forward-looking. The available market will be that presenting itself some 3-4 years after the survey mission has been fielded but the output potential of the scheme should also allow for some growth of demand once the initial load has been satisfied. Difficulties were sometimes experienced during the execution of the survey programme in determining a new demand in the absence of any indication of consumer response to electrification as such and also to the cost of the electricity. Conventional forecasting techniques were found to be difficult to apply in an essentially subsistence economy due to lack of statistical data. Survey teams were asked to synthesize the potential demand in such circumstances, using as a basis experience obtained under similar conditions elsewhere. Typical figures for the average connected domestic load were in a range of 200 to 500 W and an annual consumption of 0.7 to 1 MWh per household in a tropical or subtropical climate.

Small commercial establishments, public buildings and irrigation pumping might have a connected load of 2-5 kW per unit and the demand of small processing plants for local agricultural produce might reach about 25 kW and 75 MWh in the year. A typical composite figure for a mixed demand which includes some agricultural processing might be about 1 kW per capita and 3 MWh per capita per annum but survey teams were asked not to apply such criteria without justification. The introduction of new supplies usually show a high coincidence of demand and also periods of very low off-peak consumption; such characteristics have to be allowed for in the design of the scheme. Estimates were of course easier to make where a basic electricity supply already existed or where experience from an electrified area of similar characteristics was available. Authorities responsible for electrification have occasionally set their own targets for the level of demand and consumption bearing in mind the supply-side investment requirements that will ultimately have to be funded. In none of the 120 schemes considered hitherto under this programme has it been necessary to restrict the scale of development on account of anticipated funding constraints.

2. Hydrology

Estimation of the hydrology of small and remote river courses proved to be the most intractable part of the programme. There was generally a lack of reliable information on multi-annual flow patterns. Survey teams were encouraged to use correlation analysis with the flow regimes of similar river courses which had already been more thoroughly explored and with meteorological observations but some uncertainty often remained. Large seasonal flow variations were known or suspected in many of the cases examined and this meant that schemes had to be designed for a major overflow capacity in the wet season but were unable to produce much power during the dry season. The dry season power shortfall made it necessary to provide compensating diesel generating capacity since it was not considered acceptable to have the power supply available for part of the year only. The addition of diesel generation had an adverse effect on the economic merit of the proposals in many cases. None of the schemes reviewed offered scope for substantial amounts of storage on their own, but one or two projects conceived in association with irrigation did provide sufficient storage capacity to cover dry-season shortfalls in water run-off.

Where there was prospect of improving the merit of a scheme with more reliable hydrological data, the authorities concerned were advised to undertake a programme of hydrological and precipitation measurements which would permit the preliminary data gathered during the survey to be complemented and firmed up and the justification for some of the projects strengthened. Advice was also provided on the selection and siting of measuring gauges and on the evaluation of such measurements so that local personnel could contribute directly to the improvement of the data base.

3. Site Surveys

Because of the shortage of time, there was a tendency sometimes to rely on previously-gathered information in determining site conditions. To avoid use of inaccurate data and consequent errors in design, survey teams were instructed to put forward recommended solutions only for those projects which they had visited and to indicate clearly in their survey reports what assumptions had been based on insufficient data. The available head could be determined reasonably well from topographic measurements and the arrangements for diversion weirs and the headrace and tailrace system derived from site surveys. Sub-soil conditions could however be established only superficially and would require firming-up in the design phase.

Excessive sedimentation was a danger not fully recognized during the brief site visits. A number of the small rivers considered for hydropower development pass through eroded land and also experience large flash flows. This causes carry-over of a considerable sediment load and leads to silting of the waterways whenever the flow velocity is low. The problem faced by the survey teams was then to ensure adequate flow velocities through the diversion system at all times which made it difficult to allow for pondage at the intake even where the topography would have permitted it. Pondage would have been beneficial for the operating regime of the plant by permitting a greater degree of load cycling.

Since the outline designs had to be based on preliminary site investigation, some uncertainty was left in the costing of the civil works and project teams were asked to include a contingency margin in their estimates. All-season access to the site was considered important and adequate provision had to be made for it. Housing and services for operating personnel had to be allowed for in isolated locations. The survey team also had to select a suitable route for the transmission link to the load centres and confirm the feasibility of building the line at a reasonable cost.

The information obtained from the site survey was used for preparing an outline design in sufficient detail for a reasonable cost estimate to be made, with allowances included for all the uncertainties referred to above. Both the design and the cost estimates were reviewed by Headquarters staff in every case and were generally found to be acceptable. Particular attention was paid in this review to the dimensioning of the scheme. Principal points for consideration were:

- the number of generating units proposed, in relation to the maximum and minimum demands to be met;
- the sizing of the scheme with respect to the existing and anticipated future power demand;
- the scope offered in the design for expanding the generating facilities if future demand should warrant it.

Detailed economic studies for optimizing the number and capacity of the units to be installed were left to the final design stage. In cases where final designs were subsequently prepared in co-operation with the United Nations, the information originally established on the basis of the rather brief site surveys was generally found to be substantiated, thus confirming that the approach used for the survey programme was sound.

4. Economic Appraisal

The economic merit of every scheme found to be technically feasible and suitable for development to supply a given power market was determined in order to support a decision in favour of further study and development and an appropriate recommendation to the government concerned. Conventional economic appraisal methods were used for this purpose in which the hydro scheme was compared with an alternative solution, in most cases a diesel plant, for supplying the same power market. The result was usually expressed in terms of the benefit-cost ratio for the hydro case but in most cases the internal rate of return was also computed. The merit of the scheme was measured against the opportunity cost of capital in the economy in question. This merit was often found to be only marginal. The problem was then to decide to what extent the merit established in conventional economic terms could be supported on socio-economic grounds, for example for improving the local standard of living and promoting commercial, agricultural and industrial activity so that the ambient economy could be raised above the subsistence level.

The economic merit of many of the 120 schemes examined under the programme was found to meet the test of the economic viability. However for some of the sites the economic merit failed the test of economic viability, a result which was hardly surprising because the capital costs of isolated and remote hydro plants tends to be high; seasonal variations in water flow cause the average annual production capacity to be relatively low. Capital costs were in a range of US$ 2,500 to 4,000, inclusive of access, transmission and infrastructure. Average annual plant factors did not often exceed 40%. Such results bring into focus socio-economic issues to which the Department intends to devote greater attention in future programmes. Many of the schemes identified in the survey programme were of outstanding merit and were found to be technically feasible. Although the programme was designed to provide no more than advice to the participating governments on the prospects for small-scale hydropower in their countries and on the further action they might take towards implementation of suitable schemes, the Department attempted also to elicit interest from donor countries for funding support. This initiative has brought success in most cases.

5. Institutional Matters

Some of the countries involved in the programme had no previous experience of small-scale hydropower development and had not set up any institutional framework for the construction and operation of these plants. Responsibility was normally assigned to whatever agency was entrusted with the national electricity supply. Project teams were instructed to discuss ways of developing particular sites with these agencies, or with any other organization designated by the governments, and to include in their survey reports recommendations on the institutional aspects of further site development. Assistance was then provided by the Department of Technical Co-operation for Development within the general scope of technical co-operation, for implementing such follow-up. The most usual solution put forward was to entrust the hydropower work to a small but separate unit in which information gathered from various survey programmes could be assembled and processed and technical staff could be trained for a more active role in the hydropower sector in the country, such as in the planning and implementation of small-scale hydropower schemes.

6. System Integration

The power produced by a small hydro plant must be satisfactorily integrated into the demand pattern of the system supplied, regardless of whether this is isolated or interconnected with a larger network. As already mentioned, many small hydro plants suffer from a shortfall of production capacity in the dry season; they have a low firm output and often require support from thermal plants - usually diesel units - to meet the system demand throughout the year. The secondary or non-firm energy which they produce is difficult to determine in advance and to schedule in a regular way. In consequence, the economic merit established on average annual production figures may not be realised once the plant is in operation.

The scope of the present programme did not permit the inclusion of system integration studies and the uptake of primary and secondary energy could not be fully dealt with. In the survey programme therefore the engineers were asked to compute the average annual production costs for the hydro and the equivalent diesel case in order to bring out the incentive for replacing thermal generation whenever possible. They were also asked to show, with the aid of flow-duration diagrams, how the dimensioning of the solutions proposed had been achieved and to state what proportion of the average annual hydro output could be considered as firm. The load-duration of the small power systems to be supplied was generally unknown but the requirements for firm power were thought to be very low so that the problem of absorbing the output from a small hydro plant would be perhaps not too difficult to resolve. Detailed consideration of this problem had however to be left to the design stage.

Case Studies

Some 120 sites in 40 countries were investigated under the small-scale hydropower programme. An outline design and detailed cost estimates were prepared in each case and the economic merit determined. The principal characteristics of a few typical case studies are listed in Tables 1 - 4. The data illustrate some of the general conclusions which the results of the programme permit to be drawn. These are:

a. The agency responsible for site selection tended to give preference to localities already receiving a diesel power supply where the socio-economic impact of replacement by hydropower was thought to be more measurable and immediate.

b. The size of the catchment areas appeared to bear no clear relation to the anticipated mean flow through the turbines and hence to the dimensioning of the scheme. The installed capacity was always governed by the flow conditions and not by the load.

c. The existing or potential power market was usually well defined but there were widely differing views on the future growth of this market.

d. Seasonal shortfalls in hydro production made it necessary to retain and operate diesel plant for adequate load coverage throughout the year in most of the cases examined.

e. The cost of supplementary diesel generation reduced the economic merit of the hydro case and also tended to mask the effect of the capital cost of the hydro solution; there seemed to be no clear relationship between capital investment requirements and economic viability.

f. Time constraints prevented shadow pricing and exchange rate fluctuations to be allowed for in the cost estimates and sensitivity studies to be carried out.

g. There is no evidence that the capital costs would be greatly affected by inflationary price escalation; price stability probably arises from the large civil engineering component which allows for a major local input unaffected by world market prices.

h. The energy costs of hydropower were considerably below those of diesel and even grid-supplied energy but the lack of firm hydro production did not enable this advantage to be reflected in the economic result.

i. Each of the schemes presented involved different design concepts and this raised the question how the project might be put into effect, bearing in mind that only a limited amount of experience will be available in each of the countries concerned. This problem, as well as the difficulty of financing small-scale development of marginal importance for the country as a whole, form the principal challenge to the more widespread introduction of small-scale hydropower in the developing world.

The Outlook

The survey programme has shown that there are a number of small hydropower schemes in the developing world which are ripe for exploitation but which, because of lack of resources, could not be taken up and brought to the threshold of development; in some cases their characteristics, costs and merit had not been sufficiently explored to make further development possible. The survey programme has also shown that a relatively small input of engineering effort can be sufficient to prove that a given project proposal is feasible and promising and that its further development is justified. It might therefore be concluded that a more extensive survey effort could reveal further schemes - and possibly even more promising solutions for future implementation. While some of the survey reports compiled by the 40 field missions are not "bankable" in the conventional sense because they lack sufficiently firm information on the site characteristics, the design parameters and the costs; they present an indication rather than a justification of the potential merit. A "bankable" effort will however be needed as a bsis for further development. The Department therefore intends to give priority to in-depth feasibility and design studies for projects already identified so that financing and contracting arrangements can then be considered and evaluated. In one case, the Sor River scheme in Ethiopia (see Table 2), this approach has already met with success.

The Sor Hydroelectric Plant in Ethiopia is a good example of a small hydropower site which evolved from a site evaluation stage in our survey programme to the development stage. The scheme is currently under construction, having been identified as having excellent potential for development as a substitution for diesel power generation, which is the main objective of our programme.

When completed by the end of 1989, the Sor Hydroelectric Plant which will have a 5 MW capacity, will replace existing diesel power generating facilities at Mettu, Gambela and Dembidollo in Ethiopia and following the extension and expansion of the distribution network the plant will benefit some 62,500 people in 1989, increasing to over 212,000 by the year 2000.

Construction of the site, which is 600km southwest of the capital of Addis Ababa commenced in 1985. Based on a "run-of-river" scheme, the station involves the construction of a diversion intake, about 1000 m tunnel, 447 meters of steel penstock and a small powerhouse.

It is also intended to help developing countries to overcome particular problems which the survey programme has highlighted, in particular:

- The improvement in the data base for assessing the hydropower potential which means undertaking more thorough site exploration and measurement work, especially in hydrology.
- The establishment of an adequate institutional structure for managing small-scale hydropower programmes and of a cadre of trained personnel for putting such programmes into effect with maximum local input.
- The development of improved methods of power market appraisal, especially for new markets hitherto without an electricity supply.
- The evaluation of country-wide hydropower inventories with the aim of identifying schemes which can satisfy a new or substituted power market.
- The formulation of socio-economic criteria for the support of projects found to be of marginal merit in conventional terms.
- The study of means for mobilizing local resources of labour, materials and technical effort for the development and construction process so that the local input can be maximized.
- The mobilization of financial resources.

Adequate availability of investment capital provides the key for building small hydropower plants. The amounts to be found are not large on an absolute scale but they imply a call on very scarce resources for providing an electricity supply in an area of often unknown economic potential. Foreign currency requirements, which are the most difficult to finance, vary widely in accordance with the input which can be derived from local sources. Up to 75% of the total project cost can be in foreign currency in places where there is little experience of hydropower development and a correspondingly small local contribution. The foreign currency commitment for the 120 projects investigated under the programme was lying in a range of 45 - 65% of the total capital expenditure. Some countries can provide the whole civil engineering component and also the simpler electro-mechanical items from internal sources and require foreign purchase only for machines, some auxiliary equipment and engineering services which in total amount to 20 - 40% of the investment. Funding problems, principally for foreign expenditure but sometimes also for local costs, are the most difficult to resolve, particularly for the least developed countries. Financing support containing a major grant element may then be essential if a given scheme is to be realised. Much depends on the interest of donors to support this kind of project which can make a material impact on the social and economic situation of a majority of people residing in rural areas in developing countries.

The United Nations stands ready to continue and intensify its effort in co-operation with others in promoting and facilitating the development of this important source of energy supply for meeting, at least in part, the energy needs of developing countries.

Future Activities

It is the intention of the Department of Technical Co-operation for Development that there should be a follow-up programme of feasibility studies for some of the small-scale hydropower sites identified in the pre-feasibility phase. This will encompass the engineering services for site investigations, technical and economic feasibility study and detailed design.

A follow-up programme of construction and commissioning several selected schemes is also planned in co-operation with various donor countries, and in this connection the Department has undertaken negotiations with various multi-lateral and bilateral financing agencies to secure follow-up investment for the sites that were found to be promising in the countries surveyed.

TABLE 1. SUMMARY OF SMALL HYDROPOWER SURVEYS

Country	Benin	Bolivia	Centr.Af.Rep.
Region	L'Atakora	Cochabamba	Basse-Kotto
Project	Yeripao	San Geronimo	Kembe
River	Yeripao	Mizque	Kotto
Catchment, km^2	60	4200	78400
Mean flow, m^3/s	0.69	25.2	447
Firm flow, m^3/s	-	2.5	90
Gross head, m	109	36	14
Installed capacity, kW	740	1714	500
Firm power, kW	-	684	500
Annual energy, GWh	3.26	6.70	4.30
Firm energy, GWh	-	5.00	4.30
Project cost, US$ '000	2676	3196	1580
Date of estimate	March 1987	Apr. 1984	1986
Load centre	Natitingou	Aiquiles	Kembe
Existing supply	Yes	Yes	Yes
Demand in year	1988	1990	1986
Peak, kW	483.6	675	440
Energy, GWh/a	2.03	2.4	1.74
Future growth rate, % p.a.	9.9	13.5	-
Hydropower only	No	No	Yes
Energy cost, UScts/kWh (average)	19.6	6.86	15.8
Cost of alternative supply, cts/kWh	21.0	12.96	25.2
Type of alternative supply	Diesel	Diesel	Diesel
Benefit-cost ratio	-	1.31	1.62
Internal rate of return	10.63	-	-
Specific cost, US$/kW	3616	1865	3160

TABLE 2. SUMMARY OF SMALL HYDROPOWER SURVEYS

Country	Dominican Rep.	Ethiopia	Ghana
Region	Peravia	Illubador	Brong Ahafo
Project	Rio Malo III B	Sor	Randall Falls
River	Rio Malo	Sor	Pumpum
Catchment, km^2	122	1811	87
Mean flow, m^3/s	3.61	64.5	0.99
Firm flow, m^3/s	1.32	2.3	0.31
Gross head, m	120	110	41
Installed capacity, kW	3540	2000	560
Firm power, kW	1275	2000	102
Annual energy, GWh	19.9	8.0	1.99
Firm energy, GWh	11.0	8.0	0.90
Project cost, US$ '000	4550	5780	3230
Date of estimate	1983	1981	1986
Load centre	Local + Grid	Metu, Gore	Kintempo
Existing supply	No Yes	Yes	No
Demand in year	1983	1982	1984
Peak, kW	555	900	2000
Energy, GWh/a	8.16	3.5	7.75
Future growth rate, % p.a.	10.5	10.5	-
Hydropower only	No	Yes	No
Energy cost, UScts/kWh (average)	3.1	6.9	20.2
Cost of alternative supply, cts/kWh	7.4	14.3	23.1
Type of alternative supply	Grid	Diesel	Diesel
Benefit-cost ratio	-	2.08	1.15
Specific cost, US$/kW	1285	2890	5768

TABLE 3. SUMMARY OF SMALL HYDROPOWER SURVEYS

Country	Guinea	Honduras	Indonesia
Region	Kinkon	Sta.Barbara	Sulawesi
Project	K-Pont	Chiquero	Kolondon
River	Kokoulo	R. Blanco	Kelangkangan
Catchment, km^2	397	217	91
Mean flow, m^3/s	15.0	2.4	2.15
Firm flow, m^3/s	0.3	0.53	0.97
Gross head, m	31.2	75	103
Installed capacity, kW	2800	1440	1740
Firm power, kW	0	325	480
Annual energy, GWh	7.6	6.0	10.3
Firm energy, GWh	0	2.8	4.2
Project cost, US$ '000	6170	4180	4420
Date of estimate	1981	1984	1986
Load centre	Pita, Labe	Macuelizo	Toli Toli
Existing supply	Yes	Yes	Yes
Demand in year	1985	-	1985
Peak, kW	645	-	796
Energy, GWh/a	3.25		2.4
Future growth rate, % p.a.	23.4	-	10.0
Hydropower only	No	No	No
Energy cost, UScts/kWh (average)	9.7	11.4	5.2
Cost of alternative supply, cts/kWh	22.1*	19.0*	14.0
Benefit-cost ratio	2.26	1.67	1.08
Specific cost, US$/kW	2204	2903	2540

*based on costs of diesel-based power

TABLE 4. SUMMARY OF SMALL HYDROPOWER SURVEYS

Country	Nepal	Sierra Leone	Zambia
Region	Eastern	Northern	North-West
Project	Khotang	Betmai Falls	Luakela
River	Rawa Khola	Pampana	Luakela
Catchment, km^2	320	1580	-
Mean flow, m^3/s	1.3	8.0	8.5
Firm flow, m^3/s	1.3	0.8	1.0
Gross head, m	50.0	45.5	15.0
Installed capacity, kW	500	3000	620
Firm power, kW	500	-	267
Annual energy, GWh	4.3	20.6	4.4
Firm energy, GWh	4.3	-	0.52
Project cost, US$ '000	2228	13800	1600
Date of estimate	1986	1985	1986
Load centre	Diktel	Makeni area	Mwinilunga
Existing supply	No	Partly	Yes
Demand in year	1990	1990	1991
Peak, kW	244	2900	280
Energy, GWh/a	0.86	9.75	1.1
Future growth rate, % p.a.	10.0	-	5.0
Hydropower only	Yes	No	No
Energy cost, UScts/kWh(average)	6.80	7.96	4.46
Cost of alternative supply, cts/kWh	20.4	14.5	13.5
Type of alternative supply	Diesel	Diesel	Diesel
Benefit-cost ratio	1.19	1.22	1.30
Internal rate of return, %	12.3	13.6	13.0
Specific cost, US$/kW	4456	4600	2581

CIDA Activities in Small Hydropower

By
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Mr. Chairman,

Thank you for allowing me to say a few words about CIDA's activities in the small hydro field. It will come as something of a change of scale for me since I have just completed two weeks discussion with a Chinese delegation putting the finishing touches to the Feasibility Study for the Three Gorges Project.

It promises to be a 16,000 MW hydro installation with a 500 km forebay, so you will appreciate that I will have to change gear in order to talk to you about micro and mini hydro installations.

However, I was much taken with the thrust of this conference. It has been a long time since the UN conference on new and re-newable resources in Nairobi in 1981 gave high priority to small hydro installations, hence its time that we looked at what we have done, what we have learned and what have been our successes and failures.

For those of you who may not be familiar with CIDA I will merely say that it is Canada's main International development channel, disbursing nearly 3 billion dollars a year with energy projects accounting for some 200 million dollars annually.

Unfortunately, CIDA has not been very active in small hydro and that shortcoming is something that I wish to address. I want to search out the reasons behind this restricted activity and make some suggestions that may be helpful.

CIDA has four channels through which small hydro projects might be financed.

The first channel is the bilateral program which is essentially the official international assistance program which operates on a government to government basis. These bilateral projects are normally identified by the developing countries themselves but other times CIDA might be proactive and identify the project and then attempt to induce a request for it.

The second channel is CIDA's Industrial Cooperation Programme (INC) which is essentially aimed at encouraging private sector entrepreneurs to open up joint ventures with third world partners (for example - to open a small business or to start an energy co-op) or they might provide funds for inception studies which might lead to developmentally valuable small hydro projects to be financed by organizations other than CIDA.

The third channel is CIDA's Special Program which is aimed at financing non-governmental groups who identify their own projects and either individually or in consortium with local or other non-governmental groups implement projects directly without becoming enmeshed in government to government red tape.

The fourth channel is via the International financing agencies and international organizations such as the World Bank or the UNDP to whom CIDA contributes and thereby gets an entrance ticket for Canadian consultants and manufacturers to become involved in these international programs.

All these channels have been used to study or implement small hydro projects but there have been mixed results. How have we done? -

Few requests have arrived at CIDA through the bilateral channel because these small hydro projects do not figure in the macro-economic planning of energy systems in the developing countries. Indeed, many small hydro projects are designed to serve villages that the local governments or utilities would have no intention of serving even in the long term. Hence these villages represent new loads without any national priority or political necessity (clout) and the power which is generated does not contribute to the growing demands on the established central systems. In any case the local governments will claim that the grids are constantly being extended to serve peripheral village areas.

CIDA's Industrial Cooperation Program has attracted several entrepreneurs who try to get their favourite small hydro project implemented through offering a free study or (if the scheme is small enough) actually implementing it with a local partner. While this is all good stuff, the entrepreneur has to use a lot of his own time and money to promote the scheme and take the risks involved and few can afford it. Given the small size of the projects anything much below a 1000 KW installation is unattractive to the private entrepreneur so results have been limited.

The non-governmental groups seem to have the right kind of channel open to them because it by-passes government priority sectors but they lack the expertise to set up small hydro project. The history of NGO/Private sector cooperation has not been encouraging so far. I learn that certain engineering non- profit foundations are setting themselves up to undertake just such intermediate technology projects.

Social aspects of projects in rural areas are as important as the technology itself. Working outside government channels allows the flexibility to focus on social impacts of a project so that it might be tailored to suit a particular community.

The 18 small hydro projects performed under CIDA's programs amount to a total funding of $2.9 million. Only three were turbine installations amounting to $700,000 and the rest were studies. However we are actively promoting 12-2 MW stations in the Blue Mountains in Jamaica and if it goes ahead it will be our biggest small hydro coup. ($50 million) In Egypt we are rehabilitating several small installations on canals for about $5 million.

While the main area of interest for CIDA's small scale hydro has been the Caribbean, there is evidently huge potential for small hydro in India, Nepal and Latin America. One State in India is said to have 1000 sites for small hydro but CIDA has so far been unable to induce a request for funding the studies which might have led to implementation of these schemes.

I do not need to spend time singing the praise of small hydro for isolated villages and networks. The low maintenance requirements and limited operational skills required make this technology perfect for these applications. I would however, warn that optimisation of these installations is often a waste of time, particularly if the installed capacity is less than say 300KW. The money necessary to do the optimization studies is usually better spent on equipment and training the operators.

Thus, one of the big problems with small hydro is the high cost of front end preparatory work which leads eventually to a small installation. For example, there is no way that a team can be sent all the way to Asia to identify a 300 KW installation and to perform design optimisation studies leading to a requirement for custom made equipment. When the project area is remote from Canada it is necessary to identify a series of sites and load centres and standardize on the most simple equipment which will do the job.

Many of the very successful Chinese installations are standardized and rudimentary if not crude in their design. Many are belt transmission, with crude, or even manual governing, a volt meter, an ammeter plus a field switch and main breaker plus two lights for synchronizing and a rheostat. I saw twenty three such stations operating in parallel in a terraced irrigation scheme with 3 to 4 metres head between terraces. The design might make you shudder but it was a very successful scheme.

I also saw reinforced concrete runners for a 450 KW machine - so apparently we don't have to worry too much about efficiency and sophisticated technology unless it can be aimed at making the installations cheaper, and more abundant. Larger sized installations, of course, deserve more design study especially if they are going to feed into a large grid. Grid operation demands expensive design characteristics and often requires that the small unit should be economically competitive with marginal capacity from very large units; which is sometimes hard to achieve.

Before closing I must make a short comment on the environment as it applies to small hydro and on incentives for entrepreneurs to install small privately operated hydro stations. With regard to the environment, I would ask you not to delude yourself into thinking that there is no environmental hazards emanating from small hydro installations. The same considerations, but at a smaller scale, apply to these small installations just as though they were larger stations. Furthermore, a series of small hydro installations can often cause more deleterious effects to the environment than a single well controlled larger installation. Often this larger installation may enable funding to be available for environmental mitigation which may not be the case for small installations.

The possibility of introducing incentives for entrepreneurs to set-up privately run hydro stations in the developing countries is difficult but not impossible. Development agencies such as CIDA will be willing to do their best to get their system in place and to support interested entrepreneurs in their investigations.

So what are the basic lessons which we have learned over the years?:

FIRST try to work through informal channels rather than government to government arrangements

SECOND go for isolated situations where small hydro is competitive but try to group projects and standardize the equipment.

THIRD keep the installation simple and inexpensive

FOURTH keep the installation and equipment operator friendly

FIFTH always throw training into the package

SIXTH look after the environment and social impact.

Most importantly don't give up, the third world needs you and CIDA will be there to support you in your promotional efforts.

Can Small Hydropower Work in Developing Countries: Perspectives on Institutional Arrangements

By
D.R. Zoellner

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CAN SMALL HYDROPOWER WORK IN DEVELOPING COUNTRIES: Perspectives on Institutional Arrangements

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CAN SMALL HYDROPOWER WORK IN DEVELOPING COUNTRIES: Perspectives on Institutional Arrangements

"Commitment, not authority, will be the motivating force for development"
L.E. Harrison in Underdevelopment is a State of Mind

I. INTRODUCTION

Increasing pressures on governments to meet energy needs created by growing populations' demands for food, water, health care and a generally improved quality of life have caused already heavily indebted national economies to be still further stretched. These circumstances, when added to the environmental, technical, and financial shortcomings of large irrigation, power and water supply projects, have created the opportunity for a resurgence of interest in smaller projects and attendant institutional restructuring.

This paper will seek to identify some of these issues, to present instructive examples of both positive as well as negative experiences, to indicate some lessons learned, to suggest a new direction for the power sector, and to express the discussion in the context of small hydropower systems. This technology, when taken not as a panacea but in the proper context, can make a significant contribution to rural energy needs.

The Issues

Many of the issues that involve existing and potential programs for small hydropower implementation are connected with circumstances surrounding government-owned utilities, their financial health, the state of their existing infrastructure and attendant services and their political and philosophical points-of-view.

A recent assessment by the National Rural Electric Cooperative Association (NRECA) of rural electrification in Central America(1) summarizes the current dilemma faced by utilities throughout the developing world.

In facilities, offices are scattered and inadequate--poor coordination and communication; field staff often lack such basics as vehicles, fuel, tools and equipment leading to high energy losses; administratively the facilities suffer from lack of basic office equipment and materials, all of which result in poor customer service and needlessly high costs.

In organization and skills, some countries have no central office with a qualified staff to implement rural electrification--others have small coordinating offices for special projects; training is needed in all areas of rural electrification--design, construction, economically productive uses, etc., all of which result from a lack of concern for rural electrification and lack of appreciation for its social and economic development impact.

In staffing, salaries are declining in real terms and mid to upper management either moves to the private sector or leaves the country, resulting in both lost experience as well as higher costs for outside assistance.

The parastatal bias to urban electrification and conventional practices meant that only urbanized and industrial load centres in rural areas are electrified, not agricultural communities and farms.

Legal constraints to private alternatives exist in the form of early laws transferring control of power generation and sale from foreign and local firms to the government.

Financially, rural electrification has not been rewarding. Low consumer density means no promotion of rural electrification, which results in low connection and consumption rates, which produces a low financial return on the utility's investment, which, in turn, causes an increase in tariffs that discourages demand. This sequence of events guarantees the utilities' self-fulfilling prophecy regarding the unprofitability of rural electrification. An almost overwhelming element in the financial picture are the large sums of foreign exchange, the principal element of the countries' foreign debt. These resources have been borrowed for large power sector projects, particularly for large hydropower plants and attendant transmission. Many have run into cost overruns and delays, and for those already completed and generating surplus power, the government must continue making loan payments while waiting for demand to catch up with supply.

Lack of experience or knowledge within conventionally-trained staff results in little attention being paid to non-conventional approaches in the belief that they also are uneconomic. Small systems (hydropower, biomass, others) which reduce construction time, provide economies in transmission and distribution and which allow better use of local resources, are generally not being realized.

What this means and has meant for institutional arrangements for implementation of small hydropower systems is a mix of successful and unsuccessful experiences. The involvement or lack thereof of the national utility has been a key factor as have a long-term commitment beginning with the national government and ending with those who own and operate the systems. It also means that even though there exist successful models for institutional arrangements, the extent of their implementation has been suppressed in many cases.

II. EXPERIENCE

Since the "oil shocks" of the 1970's countries with potential in endemic energy resources have, in an effort to become less dependent, attempted to develop programs exploiting these resources, often with the assistance of bilateral or multilateral aid. Although unsuccessful experiences can be as instructive as successful ones, they seldom seem to be the basis for a following improved program or project. For a country to have a successful experience, whether on the village, region or national level, it must demonstrate self-perpetuation, from both a financial and technical point of view. This would include programs or projects that have been underway for a number of years and do not require government grants, imported equipment or expatriate assistance to maintain their viability. In their inception, several programs have used these crutches, but have since evolved to a more independent status. Other projects have stalled or been discontinued when the promoting forces employing financing or technical assistance have been phased out. Descriptions of experience from several countries follows in which one may see efforts which are clearly successful as well as unsuccessful and those which may be evolving from one phase to another.

In Thailand, after initial hesitancy, we see some Government support and emerging private sector interest; in Panama we see the lack of interest within the national utility; in Indonesia is the need for local assistance and training; in the People's Republic of China (PRC) one sees the results of long-term commitment; in Pakistan one sees the current demise of an initially successful Government-financed program; in Zaire exists the potential for a public-private model; in the Philippines locally-owned utilities served as a base from which a small hydropower program was staged; in Colombia we see the support by a financial institution of the private sector; and in Nepal we see a national development bank's key role in assisting private entrepreneurs.

Thailand

In 1980 the U.S. Agency for International Development (USAID) in an effort to obtain clarity in government agency responsibility for small hydropower development in Thailand, commissioned an institutional analysis which is summarized here(2).

Although there are more than ten organizations with a relationship to hydropower generation, ranging from the principal utility Electric Generation Authority of Thailand (EGAT) to the Royal Irrigation Department (RID), the two main potential implementing agencies for small hydropower are the Provincial Electric Authority (PEA) and the National Energy Authority (NEA). EGAT uses small hydropower only near the grid where the economics make sense within its own financial criteria.

The consideration of whether small-hydroelectricity generation is the province of PEA or NEA is an old issue. In addition to the sizable KUD project (100 MW), the UNDP was funding feasibility studies for six small-hydro projects, four of which were below 850 kW. In its prefunding process, it sought the same clarification that USAID was seeking. After one year the National Economic and Social Development Board (NESDB), which has jurisdiction, finally decided in favor of the NEA.

On October 30, 1979, a cabinet decision encouraged PEA to use small hydropower and in connection with Finnish and Norwegian donors, PEA has put together projects with sites chosen by the King. It is a matter of dispute and interpretation whether this encouragement of PEA was meant to provide exclusive jurisdiction for small hydro or simply to be an encouragement to consider it. Neither the NESDB nor the NEA has ever been officially notified of the decision to give exclusive jurisdiction to PEA. Since the NEA had 25 small hydro projects already approved in the five-year plan, it was likely that it would continue to play a role.

The contrast in differences between the two agencies' approach can be understood in three main functional areas: technology transfer, appropriate technology, and management systems. At PEA the philosophy of technology transfer is to buy the best foreign technology and train indigenous contractors in its use. At some point when experience is gained, it then supports a domestic industry. The NEA approach begins with domestic technology, and seeks to make the power for integrated rural development schemes.

In the past, cooperatives have not been popular in Thailand and the PEA spokesman was completely unwilling to discuss a role for them. The NEA spokesman supports cooperatives per se, and especially for small hydropower, believing that the profits will give incentives for them to work.

The differences between these three dimensions are at the root of the controversy. In general, PEA takes the perspective of a modern utility seeking to maintain control over the quality of its power with a monopoly over all aspects of a project. NEA, on the other hand, is seeking to keep costs down to introduce power to the rural area not having a chance to be electrified by today's more expensive techniques.

A division of labor is not clear and this is also a barrier leading to the persistence of the issue and the difficulty in its resolution. Each organization acknowledges some role for the other, and lines of demarcation are unclear. Plant capacity alone will not provide a good guideline since the size is a conclusion based on economic and local resource considerations. Even a 50 kW NEA unit may contribute to a PEA District Center. Remoteness is not a good simple divider of responsibility either for that limits NEA to villages well below the number where its concepts have merit. Nor can geography play a role in a division of labor for both organizations are national in scope.

The Royal Thai Government (RTG) has since decided in favor of NEA for purposes of the USAID-assisted small hydropower project, and although a national a policy focusing small hydropower responsibility remains absent, there has been some encouragement in the private sector in both industry for manufacturing and in the local management of small systems.

Panama

The following example(3) shows how and why some institutional arrangements never get beyond the planning stage. It is reproduced in some detail because of the inclusion of so many of the aspects addressed in this paper.

In March 1985 a three-man team from the NRECA undertook a short-term technical cooperation mission to Panama on behalf of the Non-Conventional Energy Section of the Inter-American Development Bank (IDB). The purpose of the mission was to investigate the potential for the formation of small rural electric cooperatives, together with the development of micro hydropower projects, as part of a solution to the institutional and technical dimensions of the energy needs in remote, underdeveloped rural areas.

In Panama, some 40 potential sites for micro-hydropower projects had been studied by the Instituto de Recursos Hidraulicos y Electrificación (IRHE). Missing, however, in addition to funding, was an appropriate institutional framework within which to develop the schemes. There are no rural electric cooperatives in Panama, although the Instituto Panameño Autónomo de Cooperativismo (IPACOOP) provides support and direction to a movement that includes some 300 rural cooperatives of various types.

A program of rural electric cooperatives and micro-hydropower in Panama, would be submitted to the Small Projects Unit of the IDB for funding. The Small Projects Unit is designed specifically to target the marginalized populations that often fail to benefit from larger development projects, and that do not have access to other sources of credit.

As envisaged prior to the mission, the team would select a number of potential projects from the 40 studied by IRHE. After field visits to verify their feasibility, a number of the best projects would be recommended. IPACOOP would be the intermediary or recipient of the loan, while IRHE would implement the projects. At the communities in question, IPACOOP would form rural electric cooperatives to participate in project implementation and operate and manage the systems. Technical assistance needs would be identified, and appropriate packages designed to meet these needs.

A major element in the team's findings was the potential for forming sustained rural electric cooperatives in the communities. Indeed, the wider question of what kind of institutional framework could effectively manage such small isolated systems was felt to be a major obstacle. These issues were, however, the most positive of the team's findings. At the local level, each of the communities visited was found to have had the experience of working together on infrastucture projects, and there were a number of individuals who seemed prepared to offer leadership in such an endeavor. At the national level, IPACOOP appears not only capable of forming, regulating and supporting rural electric cooperatives, but also well motivated to do so. With the necessary technical assistance, the social and institutional aspects of the program--at both local and national levels--held great potential.

A second concern was with the possibility of fabricating turbines and related equipment, as well as packaging complete turbo-generating units, in Panama. This would significantly reduce capital costs, as compared with the alternative of importing expensive equipment from abroad. It would also facilitate long-term maintenance of the equipment, stimulate local industry, and establish a local capability for replicating the projects elsewhere. Again, this was one of the more positive findings of the mission. The team was able to confirm the capability of a workshop in Santiago to fabricate turbines, and inspected--at a farm nearby--two turbines that had been made there. They appeared well made, and were operating satisfactorily. Given assistance in designs, a local manufacturing capacity could be established in Panama.

Other technical aspects of the projects presented more problems, however. Thirty-three of the projects were excluded from consideration because they had been or were being implemented, were eligible for funding under other programs, or lie less than ten km from planned or existing electricity lines. The five projects visited were found to present problems concerning hydraulic resources and topographic features that were not addressed in IRHE's studies. Specifically, dry season flows were insufficient to operate the plants as planned, and sites were typically in gorges that made construction and maintenance extremely difficult, raising grave doubts as to the technical integrity of the projects. Visits to two of the projects under construction, and to one completed plant, provided striking confirmation of these doubts. More importantly, the utility did not seem to be concerned with learning the lessons from this experience, possibly because it appears to rank the development of isolated rural energy schemes rather low in its priorities.

In strictly economic terms, the findings of the IRHE studies were found to be somewhat optimistic. According to the analysis, it may be that only one site constitutes an optimal use of scarce resources in the Panamanian economy. There is no doubt, however, that the social benefits from the projects would be substantial, and may outweigh a purely economic argument. Reliable, affordable and continuous supplies of electricity would stimulate productive activities in areas that are among the least developed in the country, as well as directly improve the lifestyle of some of the poorest communities and offer an alternative to migration to the cities.

Finally, preliminary financial analysis suggests that the cooperatives would be able to establish a reserve while servicing loans for the investment costs of the projects, at terms typically offered by the Small Projects Unit of the IDB.

On the basis of this analysis, the team recommended that: an experienced micro-hydropower specialist assist in the feasibility and design work; a local (IRHE or another organization) developer undertake feasibility and design work for the three most favorable sites and agree to undertake major repair and maintenance tasks over a 20-year period; technical assistance be undertaken for local manufacturing capability and for strengthening IPACOOP ability to form rural electric cooperatives. Not surprisingly, the utility was not pleased with the team's findings and has since transferred personnel from the micro-hydropower group to work on several large hydropower projects.

Indonesia

This example is given from an analysis in the early 1980's of the management approaches taken for three existing small-hydropower plants in Indonesia(4).

Under an energy diversification program and in furtherance of "rural modernization," the Indonesian Government encouraged development of mini-hydropower sites throughout the country. Initial rural electrification efforts made use of small diesel-electric generating plants, but in 1968, the Government began a program to establish pilot micro-hydropower projects in all provinces. By the early 1980's, over forty (40) projects with a combined capacity of over 20 MW were in operation and more were planned. The first of the three sites, Cokrotulung, was constructed by a private contractor under the auspices of the Department of Cooperatives of the Central Government and is now managed by a cooperative at the village level. A second, Maron, was constructed by the Power Research Institute (LMK) of the national utility Perusahaan Listrik Negara (PLN), later handed over to the local government. The third, at Karangasem, was also constructed by LMK and is managed by PLN.

Basic information on the projects is given in the following table:

Location	Cokrotulung	Maron	Karangasem
Year started	---	1971	1971
Managed by	cooperative	PEMDA	PLN
Installed capacity	30 kW	80 kW	80 kW
Actual Generation	15 kW	28 kW	70 kW
No. villages served	3	3	5*
No. household served	200	102 (150 waiting)	604*
Nature of consump.	lighting	lighting	lighting
Total capital cost	Rp. 25,000,000	Rp. 37,500,000	Rp. 28,300,000
O&M (monthly)	Rp. 27,000	Rp. 86,000	Rp. 381,392
Tariff (monthly)	Rp. 7/watt	Rp. 5/watt	PLN tariff
Revenue (monthly)	Rp. 40,000	Rp. 150,000	Rp. 91,000**
Irrigation benefits	3 Kecamatan	Yes	Yes
Other benefits	Drinking water	---	---

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*total served by both micro-hydropower and diesel plants

**apportioned to micro-hydropower from total revenue

The five-person PLN staff has managed the Karangasem plant from the beginning. The local people have not been involved in its planning, construction, or operation. The site has a higher potential than is now being used; only part of the water diverted from the river is being used to operate the existing turbine during much of the year. However, for four (4) months of the year, during the dry season, the waterflow drops sharply and PLN has installed a diesel generator to supply the bulk of the load during that period. Demand for power is too high for new connections to be made unless more equipment is added. The level of managerial and technical efficiency is much higher than at either Maron or Cokrotulung, but operating expenses also are much higher. The plant operates at a net monthly loss, even though the rates charged by PLN are substantially higher than those charged at Maron or Cokrotulung.

The Maron and Karangasem plants are almost duplicates, with the same installed capacity and the same equipment. The Maron plant, managed by the provincial agency, uses the existing fall of a large irrigation channel through a dam and two small weirs, which kept civil works to a minimum during construction. The Maron plant was paid for by the central Government and given to the provincial Government in 1972. A provincial agency manages technical maintenance of the project and a local revenue office takes care of financial and administrative management. Local skill was not available to correct even minor technical problems. A damaged speed regulator had reduced the efficiency of the turbine by about sixty per cent (60%), resulting in an erratic power supply, very low voltage, and dissatisfied customers. The resident technician explained that the defective part could not be repaired or replaced. At later meetings, however, factory representatives thought replacement was possible, and the PLN offered to provide technical assistance. It appeared that local management had not made much effort toward repair and that a serious coordination problem existed. There were indications that the provincial Government wanted to return the project to PLN management, in view of the lack of skills and administrative experience at the local level.

The mini-hydropower project at Cokrotulung is an example of a small-scale plant initiated and managed by a village-level cooperative. The power is used mainly for domestic lighting in three villages; it is available only in the evening and at very low voltage.

Construction costs were covered by the Government, and operational costs--mainly salaries for two part-time employees--are very low. However, a maintenance loan from the Government can no longer be amortized, because an ice factory that was a major source of income has closed. The project was, due to financial constraints, not able to even buy parts. Although the tariff was extremely low, consumers were unwilling to pay more unless they received better service.

At this site, the local organizers, despite their initiative and interest, seem to have been overwhelmed by comparatively simple problems. There was an urgent need for sound technical and financial advice, perhaps from the Department of Cooperatives or from PLN, to help the local group solve its problems and become self-sufficient.

One might conclude that: although consumers welcome generous government grants for facility construction, the policy may generate an attitude of dependence in the local setting; the general financial situation of all three projects is poor; the economic threshold between PLN and local management options is not yet clear; and local management of small-hydropower plants like Maron and Cokrotulung suffer from lack of trained technicians and managers.

The People's Republic of China

Local participation and investment has been the key. Overall plans are developed by the PRC's leadership, but local units ranging from counties to towns, brigades, and communes are in charge of much of the planning, execution and financing of the country's small hydropower projects. The national Government has focused most of its effort on providing technical support. Large subsidies were once available from the government, but most were phased out by 1985.

The PRC is the first and only country to undertake this on a large scale. To date, more than 50,000 plants under 500 kW capacity have been installed; most of them built by the people's commune's at the county level and used by the commune members, supplying electrical power for local industries and small workshops. Whereas virtually all hydropower generating sets were previously imported, PRC began local manufacture of a wide range of turbines in the early 1950's. In the early 1970's, standardization of turbo-generating equipment with outputs of 12 to 12,000 kW was undertaken. Recently the Tianjin Electro Driving Institute has developed small compact turbo-generating sets from below a kilowatt to 20 kW. Thousands of these are produced annually.

In the construction of these plants, stress is placed on maximizing use of locally available materials. This results in low costs, ranging from 1 to 3 cents/kW and a return of investment for a small-hydropower station in three to four years.

About 40 percent of the PRC's rural townships and one third of its 2,200 counties get most of their power from small hydropower plants.

Many small hydropower projects started as autonomous systems, but were later linked together in local grids or connected to larger central grids. By relying on self-construction, self-management and self-consumption, the PRC has demonstrated that given the necessary incentive, spirit of cooperation and local leadership, power projects can be carried out successfully at the local level--a blend of local and national involvement, private initiative and public cooperation.

Pakistan(5)

In the mid-1970's the Appropriate Technology Development Organization (ATDO) of the Ministry of Science and Technology with technical support from the University of Engineering and Technology in Peshawar, launched a program to disseminate small-hydropower technology and install micro-hydropower plants in remote rural villages in northern Pakistan. Their objective was to create appropriate designs whose technology and cost could be absorbed by the local population.

Only after it was assured that the entire community will share in the benefits accrued from developing this potential, did ATDO approve a project. After discussions with ATDO personnel, villagers bought materials such as cement or steel that are not available locally, and built the intake structure, forebay, canal, penstock, and powerhouse.

Villagers followed small wooden models in place of blueprints. Canals to bring water to the powerhouse are similar to those which have been used in village irrigation systems in Pakistan for centuries and, therefore, villagers are familiar with them and construction presents no problems.

When a specialized skill, in electrical work for example, was needed, the villagers had to find the electricians in the towns or cities.

In designing the various components of the plant, there was a trade-off between cost and labor. A villager designated by the community operated and maintained the plant on a daily basis. He ran it with ATDO supervision for several days, mastering the needed skills.

Now that the technology is more widely accepted, government financing, originally used primarily to promote development of hydropower, is being phased out. ATDO was providing technical support and fielding about half the expense of the generator. The provincial government was assuming the balance of the cost of the generator and some distribution costs as well. Local villagers were responsible for civil works and the distribution system.

The financial assistance from the government was not repaid. Once the plant is operational, it becomes the property of the village which is then responsible for all costs associated with operating and maintaining it.

The village leaders, or other influential individuals from the village, working in league with the community, managed the system and made operational decisions such as setting the tariff or determining the hours of operation of the plant.

Ranging from about 5 to 15 kW, nearly 40 plants had been installed by 1983 and a number of plants, ranging in size up to 50 kW were under construction. In addition to generating electrical power primarily at night to replace wood or expensive fossil fuels used for lighting, direct shaft power was used to drive a variety of tools and agro-processing equipment during the day at several sites. The installed cost of these schemes ranged from $350 to $500/kW (in 1981 dollars).

Since 1983, with the removal of Government financial assistance and the reduced availability of the technical skills of ATDO, the program has stalled, largely because of the established dependence.

Zaire[6]

The assessment of Private Voluntary Organizations (PVOs) as an alternative institutional vehicle for implementing mini-hydropower development in Africa was one of the objects of this case study. Various arguments have been made for and against PVO project implementation in Africa and elsewhere. On the "pro" side, it is said that PVOs provide the distinct advantage of serving as resident advisors for project construction and management. Moreover, they act as independent agents generally free of direct--and often constricting--ties with the political and bureaucratic trappings of formal donor organizations. On the "con" side, it is argued that there is little formal technology transfer that occurs with project implementation in remote rural settings--PVOs provide not only the technical assistance, but also, do the work. Put differently, projects appear where PVO missions are found; other areas remain untouched. Local people benefit from the results of this work, but can't duplicate these efforts elsewhere.

PVOs in Zaire are extensive, well-organized and often represent the only effective institutional base outside of the capital city. The Protestant Mission system (mostly American) has a network of 67 hospitals, 500 dispensaries, and some 2,000 employees. In addition, this system effectively manages some 3,000 primary and secondary schools for the Government. The countrywide organization of Missions represents 6 million Zairian members with facilities at 11,200 locations. The organization effectively acts as a national institution for development planning and implementation and numerous donor groups channel assistance through its programs.

Experience in the development of a 350 kW project at the Karawa Mission Post in Northern Zaire with bilateral assistance from Germany and the U.S., may be summarized as follows:

Project characteristics	Project performance
Impetus for development	Excellent. Probably stronger, with greater likelihood of follow-through.
Technical capability:	Relatively good. Adequate to implement project, but required time to "learn" technology and couldn't always anticipate problems and needs.
Financial capability:	Uncertain. Largely irrelevant in terms of implementation but could prove stronger in the continuing viability of the project.
Cost-effectiveness	Uncertain. High unit capital cost, considering its one-time-only character; but low engineering cost (volunteer technical assistance and supervision).
Construction period length:	Probably comparable.
End-uses and economic feasibility:	Relatively good.
Repeatability:	Poor.
Technology transfer:	Poor.
Impact on national energy strategy	Limited (poor).

On balance, if the choice is between a PVO-implemented and a government-implemented project, the PVO approach is preferable, looking at the short-term performance of a given project. In terms of a long-term program for small decentralized hydropower, however, there may be an alternative institutional arrangement which could take advantage of the strengths of both approaches. This arrangement involves the participation of PVOs, the national government, and private engineering firms. The key features of this approach are described below.

- The government's role would consist of several important programmatic functions, but would have only limited involvement at the project level.

- PVOs would be involved in any project approved by the government at a PVO-operated facility. These projects, over the long run, could represent only a small percentage of the total national small hydropower resource development. In the short run, PVO sites would probably receive the bulk of the attention.

- The bulk of the implementation of projects, particularly non-PVO projects, would fall to one or more private small hydropower development companies. The firm would contract with the developer (PVO, village community, private investors or industry, or government, including the national utility) for services needed on a case-by-case basis.

Philippines

The cooperative approach is conceived in the belief that rural electrification could only succeed by harnessing the private initiative of the rural people themselves. There are several factors affecting the success of rural electric cooperatives:

- a favorable political climate;
- a clearly designated, mutually agreed upon service -- no future conflicts with the national utility;
- reasonable wholesale purchase rates in distribution cooperatives;
- professional-quality management;
- continuing availability of long-term capital loans at reasonable rates;
- commitment to area coverage to realize full social and economic benefit;
- retail rates low enough to encourage full use of service;
- system objectives and project progress must be communicated to maintain interest and understanding;
- continual training for all staff levels;
- close staff participation and leadership in community development;
- customers must provide participation and leadership in the democratic business of the cooperative; and
- efficient and innovative consumer service and education.

A cooperative-based rural electrification program in the Philippines has provided power to more than 18,000 villages in 12 years. Annual meetings have large turnouts and many activities. Many of the over 100 cooperatives have also become involved in charcoal production, school lighting, school waterworks and vegetable gardening.

In 1979 the National Electrification Administration (NEA), which had developed the nationwide system of locally owned and operated electric distribution cooperatives, was assigned the task of executing a mini hydropower development program within these cooperatives. Less than three years later, it placed five power plants in operation, initiated construction on five more sites, placed equipment orders for about twenty (20) plants and completed forty-five (45) feasibility studies. Initially, overseas firms supplied most of the electro-mechanical equipment, but within the next several years, some of the equipment was manufactured locally by AG & P Pacific.

An important element for their success is the fact that the local management has been well qualified. The cooperatives are large enough to support a full-time, trained, electric utility manager and staff. The capacity of these units is generally over 500 kW.

Colombia(7)

The International Finance Corporation (IFC), an institution of the World Bank Group and created in 1956, promotes the growth of productive investment in developing countries by the private sector by playing three main roles. The first is to bring together the finance, technology and management needed to promote specific investment opportunities. The second is to encourage the flow of private capital from within developing countries and from capital-exporting countries. The third is to provide technical assistance to member governments in creating an investment climate conducive to private development.

The IFC:

- will finance some projects with up to 75% to 80% government ownership;
- will provide resources to development banks which are 100% government-owned;
- will never finance a project alone;
- considers itself a lender of last resort;
- rarely finances more than 25% of the project cost;
- will never take more than 20-25% of the share capital;
- does not provide money where its maximum 25% participation equals less than $1 million;
- does not provide loans on concessional terms;

In 1980 in Colombia, a hydropower-rich country where only 13% of the rural population is served by the grid, a group of entrepreneurs, mostly engineers, developed a prototype mini-hydroelectric unit creating considerable interest at an international fair and subsequently, between 1981-82, 26 units were installed successfully, mostly on private farms with 2 units in small villages. In 1981 the IFC was approached and agreed to help the sponsors analyze and structure the project and required the new company to attract local investors. In view of the pioneering nature of the project IFC relaxed its minimum limit of $1 million. IFC is the only non-Colombian shareholder and all assistance from the IFC was given in the form of share capital ($200,000). After 1984 company sales of around 200 units per year averaging 20kW capacity were expected.

In view of the fact that capital costs to install these units varied from $12,500 to $250,000, depending on the unit capacity and the site characteristics, IFC helped the Colombian financial institutions devise a system of financing sales of the equipment. This agreement with those financiers in which IFC is a shareholder or to which IFC has provided funds through the World Bank, would be able to provide a variety of financing packages to rural communities or small farms with 3 to 7 year pay-back.

Nepal(8)

The Agricultural Development Bank of Nepal (ADBN) is the principal financial institution in Nepal specializing in agricultural and rural credit and was established in 1968. The ADBN's main functions are:

- to provide short-, medium-, and long-term loans to individuals, cooperatives, cooperative bodies and firms engaged in agriculture and allied activities.
- to undertake the banking functions specified in the Commercial Bank Act of 1964 with the approval of the Nepal Rastra Bank.
- to perform other functions as prescribed by the Government of Nepal from time to time.

Nepal, a country with tens of thousands of megawatts of potential hydropower, has a long history in the development of water resources for traditional water powered mills. In the 1960's with bilateral aid, turbines began to be manufactured and installed and in 1973 the ADBN began to finance the projects. By 1983 approximately 200 turbines (crossflow) with capacities of 5 to 20 kW had been manufactured, installed and were operational. More than 7 manufacturers in Nepal have a combined capacity of 145 units/year. The turbines are installed mainly to run agro-processing units such as rice hullers, wheat or maize grinders and oil expellers. Some turbines are also used to lift water for hill irrigation and generate electricity to light the mill house or mill owner's home on a limited scale. The Bank, manufacturers and owners are attempting to increase the use of turbines by diversifying their applications to:

- lift water for hill irrigation;
- run rural and cottage industries;
- generate electricity for rural electrification;
- dry grains and spices;
- operate other agricultural equipment such as wheat threshers and winnowers.

The ADBN's lending terms and conditions for these projects are:

- the maximum loan amount is 85% of the total cost--the balance is contributed by the borrower in the form of labor and local building materials.

- the interest rate is 15% per year on the outstanding loan amount.
- the repayment period is 5 to 10 years.
- there is an annual or half-yearly repayment schedule, depending on income.
- land and/or a building can serve as collateral.

The project loan development proceeds as follows:

1. A potential site for the turbine is identified by an entrepreneur or a group of farmers.
2. The completed loan application form is submitted to the ADBN branch office, along with a description of the programs to be carried out.
3. The ADBN asks a turbine manufacturer to conduct a technical survey and feasibility study.
4. The ADBN receives the quotation for a technically feasible site from the manufacturer for a complete turnkey assignment.
5. If, after the Banks economic and financial feasibility assessments, the project seems acceptable, the loan is approved and the borrower informed.
6. The Bank sends an order letter to the manufacturer to build and install the turbine to suit the specific site and the borrower completes all the civil structures, including the canal and mill house as designed by the Nepalese firm.
7. The completed equipment is installed by the borrower and the firm at the site.
8 The completed plant is handed over to the borrower, the ADBN makes payment to the firm on behalf of the borrower, who, in turn, repays the ADBN.

The project costs, approximately \$8,000 - \$10,000 are repaid, usually, in 4 to 7 years and the financial rate of return on a turbine for agro-processing is around 37 percent.

In addition to the Nepalese firms that manufacture and implement the small hydropower mill projects, the ADBN receives assistance from the Asian Development Bank who provides low interest rural credit.

III. LESSONS LEARNED

Experience with institutional arrangements for small-scale rural electrification and small hydropower projects has yielded a number of lessons about factors that contribute to the success or failure of such projects. It is easy for a country trying to implement small hydropower schemes to work independently--needlessly repeating the mistakes made by others, not benefitting from years of experience in other countries. Some of the lessons learned from years of experience follow.

Centralized management of small-hydropower development becomes less viable as plant capacity decreases. Implementing several small schemes in remote rural areas requires complicated logistical arrangements and can clearly be more cumbersome than installing single large scheme. Each small scheme needs numerous levels of costly and time-consuming studies. With smaller, isolated schemes in areas with little previous experience in the benefits and uses of electrification, it is difficult to achieve the active planning for productive use that must be an integral part of centralized planning.

The Philippines is undertaking a program for joint central and local development of mini-hydropower projects. The work is not being done through the national utility, but through the NEA, using a network of local cooperatives. Donor funds from a number of sources available to NEA are being used to design and construct small-hydropower sites. The local cooperatives are responsible for construction management, operation, routine maintenance and payment of the debt service.

In Nepal the ADBN is funding a program to install micro-hydropower units in remote areas. These are primarily for milling, but in some cases, generators are added to serve a lighting load. Here the mill owner, not the national utility has the responsibility to provide electric service to nearby residents as he sees fit, and he is also responsible for paying the debt service. In this sense, the mill owner is the project manager.

An important element in the success of these small hydropower programs has been well-qualified local management. In the Philippines the cooperatives are large enough to support a full-time, trained electric utility manager. In Nepal, the systems are controlled by a local businessman, the mill owner and operated as a commercial enterprise.

Central technical support service must be available. There must be a central focus, not necessarily in a managerial sense, to provide a concentration of services somewhere. Although the smaller projects should have the support and input of their local communities, they cannot be expected to service by themselves without some source of technical assistance. These services are essential at some time for many small hydropower schemes and they should be available on an as-needed basis from a central pool or national organization.

Some of the earlier, privately-developed sites in Indonesia suffered from a lack of this technical support for construction and system maintenance. An example of this problem also occurred in Liberia, where a project that was a joint effort by USAID and the Peace Corps encountered many difficulties because of technical aspects of the project. No in-country backup support was available and long delays and numerous cost increases resulted.

Feasibility studies must determine whether an adequate load is present or capable of being developed. However obvious this may seem, such studies are not always conducted. A system's viability depends on its being able to pay for itself. For all decentralized hydropower schemes, end uses for the power generated must be identified. In some cases, sites have been selected primarily on the basis of technical merit and the selection has been followed by a search for a potential load. Such an approach wastes resources and manpower. In Rwanda, for example, extensive studies and preliminary designs were made for a 20 kW site at Kaviri Falls. No clear use for the power was identified, yet momentum for the project kept building. In contrast, Nepal has ready-made users for the power and the newly constructed hydropower mills can pay for themselves in a few years. Planning should begin with a clear understanding of how the power is to be used.

Adapting locally appropriate approaches can significantly reduce small-hydropower costs. Economies of scale are often used as an argument against small hydropower schemes; as plant capacities decrease to below several hundred kilowatts, costs installed per kilowatt can rise sharply. However, experience around the world supports this argument only if the conventional approaches for implementing large-hydropower projects are simply scaled down and used for small hydropower. In remote areas with small-decentralized plants geared to local communities, new conditions are often encountered and the approach should be modified accordingly. This applies not only to civil works and equipment selection, but to the entire project--system configuration, management structure, tariff concepts. For small hydropower, local participation in planning and the work force and local manufacture of equipment should be considered whenever possible. In both Nepal and Pakistan, costs per installed kilowatt were kept in the low range by numerous means: local manufacture of turbines; villager initiation, operation and management; and an overall configuration designed especially to meet the needs of the community, not adapted from some standard but inapplicable industrial pattern.

The technical approach to development must be appropriate to the need. Micro-hydropower schemes should not be scaled-down versions of large hydropower systems. Several programs have attempted to implement micro- and mini-hydropower using the same approaches, control, and quality requirements appropriate for large-scale developments or for small-scale developments in industrialized countries. These approaches lead to very high costs for complex electromechanical equipment, overdesigned civil works and inappropriate distribution systems. Examples exist in Honduras, where bid specifications required expensive, custom-developed turbines, rather than pre-engineered units; in Liberia, where the identified loads would have been served better by mechanical power than by electrical power; and in Malaysia, where long, imported steel penstocks were recommended when simple earthen canals with shorter penstocks may have sufficed.

These examples illustrate some of the mistakes--and some of the achievements--that are part of the record for small hydropower schemes in numerous countries. Many of these problems have been discussed here: poorly chosen or adapted technical designs in Panama, lack of local understanding and participation in Indonesia, insufficient market for the power, also in Indonesia, success in combining central government planning and support with local resources and management in PRC; the model for implementing small hydropower schemes through private and voluntary organizations in Zaire; the successful staging of a small hydropower program in the Philippines from existing rural electric cooperatives; and the development assistance experience of financial institutions for private sector projects in Colombia and in Nepal.

IV. NEW DIRECTIONS

As mentioned above, the power sectors in many developing countries are now faced with a dilemma like never before. On the one hand is the extent of the utilities' foreign debt. By the mid-1980's developing countries were spending over $40 billion each year on electricity projects. A portion of this, of course, came from loans and grants from international aid agencies. Since 1982 the World Bank has lent $2 to $3 billion per year for such projects. On the other hand is the extent of electricity demand. More than 2 billion people worldwide live without power and the World Bank projects that electricity use in developing countries will grow at six (6) to seven (7) percent per year in this decade, and developing countries will have to invest $60 billion in electric power each year to keep up with a demand growth rate of seven (7) percent(9)(10).

It is estimated that to increase national income by one percent, energy consumption must increase by 1.3 percent. More specifically, FAO research has indicated that commercial energy inputs for agriculture must increase by 2 percent for every one percent growth in agricultural output.

A $32 billion shortfall between utility needs and financial capabilities was forecast for Latin America and the Caribbean, and Chile was typical with a planned construction budget of $1.4 billion for 1984-1988, scheduled interest payments of $1 billion and operating revenues of just $1.1 billion(11).

The answer seems to lie within new financial options for developing countries and the following list has been suggested(12):

- non-recourse and limited financing (or project-specific financing);
- leasing of individual pieces of equipment or plants by local or foreign investors;
- private ownership or operation of energy producing or distribution agencies;
- counter-trade, exchanging export goods for energy imports;
- developing financial instruments to fund local costs (ex: new financial intermediary);
- revenue bonds, w/yield tied to enterprise profitability;
- tax-exempt bonds; and
- sale of energy futures--force large users to seek stable, long-term price contracts.

Also, typical of recently implemented vehicles designed by development banks to promote the flow of international capital to developing countries by guaranteeing (on a fee basis) against non-commercial risk is the World Bank's Multilateral Investment Guarantee Agency (MIGA). This service provides for:

- transfer risk (host government restricts conversion and transfer of foreign exchange);
- loss risk (host government action leading to loss of ownership, control or benefits);
- contact repudiation risk (outside investor has no recourse to adequate forum, faces undue delays, unable to enforce a favorable judgement);
- war and civil disturbance risk.

The other significant implication of this trend is the creation of opportunities for other organizational and regulatory structures, that is, institutional frameworks, that provide greater inherent incentives for management efficiency and consumer responsiveness and thus greater success. Principal among these are options for decentralization that would, to the extent possible, encourage competitive market forces. Participants in this new direction would include the public as well as private sectors and the construction, ownership and management of energy enterprises could even include local or foreign parties or joint ventures.

In a recent worldwide analysis of rural electrification(13), a World Bank economist, in making the case for local, private development with government support, noted, for example, that there are almost 17,000 privately-operated rural electric networks in Indonesia and though few can match the service and prices offered through the official PLN program, these private facilities demonstrate the existence of substantial resources and willingness to pay. The mobilization of these resources on a more systematic basis could significantly offset the substantial shortfall between the official national plan's rural electrification targets and actual funds available to the Government. The village level organizations such as private rural electric operators and rural cooperatives could play a vital role here. The Government could coordinate activities of such village organizations and provide the necessary policy framework and technical support to enable PLN to electrify rural areas more effectively.

Finally, to answer the question posed in the title of this paper "Can Small Hydropower Work in Developing Countries: perspectives on institutional arrangements" one should probably turn it around an ask "Can Institutional Arrangements Work in Developing Countries: perspectives on small hydropower." In any case the answer seems to be yes and although the track record is mixed it seems clear that opportunities are emerging for more institutional flexibility in the power sector which should translate into an even broader range of experiences for developing countries in the near future.

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Global Markets for Small Hydro

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GLOBAL MARKETS
FOR
SMALL HYDRO

July, 1988

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Why do we want to look at international markets?

Because:

- the Canadian market is not market-driven and is thus small;
- the U.S. market is shrinking and becoming extremely clouded;
- the big market action will be in developing countries.

So let me begin by setting the stage - just what does that developing country market look like?

First of all, though no comprehensive assessment of the world's small hydro resource has ever been compiled, estimates suggest that the potential lies between 160.000 and 500.000 MW.

To take advantage of this potential, at least 28 developing countries identified by the World Bank have established government small hydro programs. Of these, China, India, Pakistan, Nepal, Thailand, Indonesia, Brazil and Columbia all have established varying degrees of local small hydro turbine manufacturing capability.

The renewed interest in small hydro in many developing countries comes as a result of a variety of factors. First, if available, it is indigenous and, if closely situated to demand, often well matched to the needs of dispersed, rural populations. In addition, small hydro development lends itself well to local participation - from civil works through manufacture to operation. Also, the increasing cost of conventional power and the difficulty locating project financing has led to a search for alternatives.

Enormous unsatisfied demand and constrained supply opportunities characterize the electric power sector in many developing countries. And it is important to point out that this situation exists despite the fact that huge resources have been devoted to establishing Third World electric power systems over the last 25 years. Yes, there is a fuelwood crisis in developing countries. But there is also a power crisis.

In fact, approximately 1.7 billion people in developing countries are without electricity. To meet this demand, the World Bank estimates that developing nations will require investments in the electric power sector alone of $65 billion annually for the next 10 years. This money is simply not available. Of the $650 billion required, the Bank estimates it could supply $30 billion. Thus the mobilization of financial resources becomes a major issue.

While officials in the Bank believe there is scope for small hydro, most of the Bank's planned investment has been, focused on large projects requiring large sums of capital.

There is no central clearing house for information on small hydro in the Bank - a small hydro project usually results as part of a larger undertaking, often as a subcomponent of a major power initiative.

Now while the Bank, like a number of other agencies, agrees that the most likely scenario for successful small hydro development in the Third World depends on private enterprise, and that much of the manufacturing for small hydro can be undertaken locally, it also suggests that the Bank itself is not necessarily in the best position to help bring such an eventuality about. The Bank is rarely approached to lend for small hydro projects.

The Bank further suggests that utilities and developing country governments must pursue efficient, market based policies wherein prices reflect the true cost of electricity supply. While recognizing that governments often use utilities as instruments of social programming, officials at the Bank suggest that the cost of electricity supply must be used as a benchmark and that deviations from it can only be justified if an exceptional case can be proven.

However, the Bank is willing to look at innovative financing options and recognizes there are some successful pioneering schemes which have mobilized private sector capital markets.

A small group within the Industry and Energy Department of the Bank has begun to work on mini hydro development (less than 500 kW) combined with private sector investment.

In a number of countries which exhibit good resource potential, viable rural demand, a positive political framework for private sector involvement and some local technical capability for in-country manufacture, the Bank hopes to identify appropriate projects that will interest the private sector. The intent of these projects is not to demonstrate the technology which the Bank says is well proven, it is to develop and demonstrate the investment framework for private sector involvement in decentralized, small-scale hydro.

What about CIDA with respect to small hydro?
In the broad context, CIDA has, for the past number of years, been pondering the question of customization versus standardization. The Agency is now moving toward the opinion that small hydro sites should not be individually designed. While the Agency realizes that civil works such as the dam, penstock and powerhouse may have to be designed for each site, it is inside the powerhouse that CIDA would like to see standardization prevail. In fact, CIDA argues, for Canadian companies to achieve commercial success abroad, they will have to select and produce a narrow range of package systems that can be used in a wide variety of circumstances.

More specifically, however, CIDA's own experience with small hydro has not been positive. The Agency has the view that small hydro is more expensive than the figures usually quoted. According to its own estimates, typical costs are likely to be in the $4000/kW range or more.

Because there is virtually no domestic market for small hydro, CIDA argues, it is very difficult for Canadian industry to develop to the point where it is self-sustaining.

However, CIDA has identified small hydro opportunities in Jamaica, Gabon and Egypt.

What about the United States Agency for International Development?

Let me read you a quote.

> "The private sector has been shown to be an effective mechanism for implementing and lowering the cost of renewable energy alternatives. The private sector has also been effective in mobilizing capital and providing smaller-scale and technically reliable renewable and alternative power sources - under the right public policy conditions."
>
> - Office of Energy, USAID, February, 1987

I read you this because it is going to help us focus on Canada's small hydro niche.

Because small projects require less overall capital, the option of private sector involvement in project financing becomes a real possibility. There is money in developing countries - particularly private sector money. Accessing these funds for power generation projects could play a significant role in reducing current and future electric generation shortfalls.

So we have substantial electricity demand,
we have a small hydro resource,
we have little or no aid money to develop this resource,
but we have a private sector with capital that is interested in small hydro ventures.

Therefore, the linkages between the Canadian private sector and the developing country private sector need to be strengthened to develop that resource and supply that demand.

The local developing country private sector needs to be involved right from the feasibility study and construction phase. Only then are they likely to adopt the technology and become the primary vehicle for implementation.

The Canadian private sector, on the other hand, needs to be involved as a joint venture partner that is willing to license equipment (after first adapting it to developing country needs), establish a local presence, provide after sales service and spare parts and preferably invest in the projects themselves. If you're preoccupied with simple sales of equipment then forget it - the competition is offering better terms.

In fact, developing countries are already looking at this option. RCG/Hagler Bailly & Company, an international consulting company based in Washington D.C. says Turkey, Pakistan, the Philippines, Indonesia, Thailand, Jordan and India either have or are considering developing policies aimed at encouraging private sector involvement in power generation. In Pakistan, Hagler Bailly suggests, "of the estimated maximum potential of 2500 MW, some 1500 MW could be installed before 1995, cutting the power generation deficit by two-thirds." Of this, about 550 MW is small hydro.

"The private sector in Pakistan has shown serious interest in investing in power generation and has the financial resources to do so." Hagler Bailly estimates that to successfully bring on the full 2500 MW, a total capital investment of between $3 and $4 billion would be required.

While there are constraints, i.e., private sector entrepreneurs in Pakistan are concerned about the price the utility is willing to pay for privately generated electricity; and the Pakistan utilities have concerns about the private sector's ability to generate electricity, nonetheless the policy developed in Pakistan is, according to Bailly, "one of the first of its kind to be formulated in a developing country."

Why should the private sector in developing countries be interested in power generation? There are four reasons: First, it is directly affected by the power shortage; second, it has the ability to attract technical and managerial resources; third, it is interested and anxious to get into the power generation field because of its potential profitability; fourth, it can install large quantities of power generation faster and can mobilize capital faster than can the national utilities.

It needs to be said, however, that private sector power development in developing countries will not necessarily take the same shape as it has in the U.S. or is conceived of in Canada. In fact, due to local cultural customs, laws and regulations, and remembering that this is not something developing countries have ever done before, progress is going to be slow and developing country driven. Nevertheless, an obvious window is appearing and Canadian firms must prepare themselves mentally for creative approaches to project financing which go beyond what we have become accustomed to in North America.

It is perhaps an irony that one thing working in favour of private sector involvement in small hydro is the increasing debt burden of developing country governments and utilities.

Though no exact figure is available, total Third World utility debt is estimated by the Worldwatch Institute in Washington, D.C. to be over $US180 billion - 20 percent of the Third World's accumulated foreign debt. Because the capital to finance large projects is increasingly hard to come by, smaller projects, which could make use of private sector capital are becoming more appealing.

The United Nations is another player but at this moment it is not approaching small hydro with a view to private sector involvement. Nonetheless, the Agency does offer an entry route to companies exploring small hydro opportunities in developing countries. With financial assistance from Japan, Norway and Sweden, the United Nations Department of Technical Cooperation for Development (DTCD) has completed surveys of 120 selected small scale hydropower sites (ranging from 500kW - 5 MW) in 41 developing countries.

I just want to mention one other group that is looking seriously at the concept of an increased role for the private sector in developing countries and that's the U.S. Department of Commerce. The role of this U.S. federal government department is the identification of commercial opportunities for American business.

Because of the current developing country government and utility financial situation, Commerce believes there is a role for small private firms hoping to do business in small hydro. But they will need to identify a niche market. This will involve finding a host country government that is receptive to the notion of private sector power generation and Commerce itself is currently helping U.S. firms do just that in the Caribbean and South America.

This is starting to get me into the competition section of my paper so before I get ahead of myself, let me conclude this section by saying there is no doubt that a global opportunity for small hydro exists.

But Canadian companies that intend to enter the international export market should do so with caution and with close attention to their capabilities. In principal a company should have:

- a detailed, realistic export plan;
- sufficient funds to finance an export effort over at least two years;
- someone on staff who can dedicate themselves to the process almost completely. Technical experts are not usually the right people for this task. Marketing is a skill like engineering or financial analysis and those responsible should be capable. In addition, for developing country exports, the assigned individual should be more than marginally interested in the Third World;

The company must also:

- accept the fact that frequent travel to see the client is essential. Five or six trips over two or three years will be minimal in order to win a significant contract;
- be very flexible in its attitude towards financing the project and be willing to spend as much time on completing the deal once the client is identified as they spent on finding the right client;
- spend time on understanding how the Canadian government works and how to apply for funding and, where necessary, lobby for support;
- spend time cultivating very good relations with a bank knowledgeable in the market so that your approach to a client is with the bank as a member of your team;
- appreciate that the cultural difference of each client is important and work to understand and accept these cultural differences;

All this assumes that your product is excellent and price-competitive, and that your technical support and corporate follow-up is superior.

It is not an easy market to capture. However, if pursued with effort and focus, it can bring major financial rewards.

But what delivery capability does the Canadian small hydro industry have? While it is not a large sector, Canadian small hydro entrepreneurs have experience in Canada, the U.S. the Caribbean, South America, Asia and Africa. The industry is young, vibrant and most importantly, it has recognized the need to collaborate with developing country entrepreneurs in order to meet the export challenge.

Of course, if there is a market out there, we're not the only ones who know about it. So what's the competition doing? Well if we look at the British periodical, International Water Power and Dam Construction, we see that since 1984, when this periodical began publishing its small hydro turbine survey, a total of sixty-one new companies have been added to the list, while only six have been deleted. Something must be up!

My guess is that the establishment of new firms may simply be a reflection of optimism that small hydro markets in the Third World will soon develop on a large scale.

Let's look at the U.S. industry first.

Evidence suggests that the U.S. small hydro industry will not offer as much competition internationally as Canadian companies might at first suspect.

According to industry analysts in the U.S., American small hydro firms are typically small, without capital and lack aggression overseas. As such, they are not prepared to involve themselves nor will they easily penetrate international markets.

The strength of the American industry lies in its familiarity with private sector involvement in electric generation projects. It is not certain, however, that this experience will be put to work because, while some developing countries are looking at private sector participation in power generation, the policy framework to allow such participation to proceed may not be put in place soon enough to prevent the U.S. small hydro power industry from losing its critical mass. A number of previously active companies are getting out of the power business altogether.

There are currently fewer than 20 companies with between 10 and 25 employees active in small hydro in the U.S. This is down from a high of some 150 companies just three years ago. Of the remaining firms many are expanding into cogeneration.

To the extent possible, the U.S. National Hydro Power Association, working in tandem with the U.S. Export Council for Renewable Energy (a conglomerate of the U.S. renewable energy industry) keeps its members informed about potential involvement in USAID (U.S. Agency for International Development) or other government targetted projects.

While the Association feels that small hydro's success in developing countries will depend on the active participation of the U.S. private sector, it has a more serious problem to deal with at home. Due to environmental constraints, site development in the U.S. has come to a virtual standstill. Because of these and other regulatory problems, the major preoccupation of the Hydro Power Association is not with exports, but with the development of new U.S. sites and the re-licencing of existing ones.

Industry itself admits it has become used to designing projects in an effort to recover its investment in three to five years. The realization that investments in Third World nations might not have such fast paybacks and that one might have to change one's design to meet local conditions has left many U.S. industry players wondering whether they can afford the committment.

THE EUROPEANS

While U.S. companies may not offer severe competition, the same cannot be said for European firms. Numerous large companies from Austria, France, Switzerland, Italy, Germany and Scandinavia manufacture small hydro turbines and associated equipment and have been exploring and developing new Third World markets for several years.

In part, the search for new markets is motivated by the same factors which are now concerning the Americans. It is simply getting increasingly difficult to obtain approvals for small hydro site development in Europe. While domestic upgrading and refurbishing of sites is still proceeding and while Germany plans to proceed with some 27 projects over the next several years, an increased awareness of environmental concerns has meant that most undeveloped European capacity will remain as such.

One of the most active government agencies in Europe in terms of its support of small hydro is the German Agency for Technology Development. Acting as a bridge, it helps German small hydro firms find business in developing countries. An array of services are provided from site assessment to assistance in arranging financing, through, for example, development Banks. A total of 3000 small hydro units have been installed in developing countries by West German firms.

In general, European companies have built strong reputations from a long history of good domestic and international sales.

I refer to companies such as:

Gilbert Gilkes and Gordon (England)

Ossberger-Turbinenfabrik (W. Germany)

Kvaerner Hydro (Norway)

Ateliers Bouvier (France)

Flygt (Sweden)

But competition won't come only from the Europeans, but from developing countries themselves.

China, for example, is the world leader in terms of domestic installations of small hydro equipment with approximately 90,000 turbines installed in rural areas - 50,000 of which are on sites less than 500 kW.

Whereas in the 1940's and 1950's the Chinese imported most of their small hydro equipment, the establishment of local manufacturing capability has meant that for the last decade the Chinese have been attempting to export their technology throughout the world - including to North America.

As stated earlier, a number of other developing countries have established local small hydro turbine manufacturing capability. As well as China these include Brazil, Colombia, India, Indonesia, Nepal, Pakistan and Thailand. Often, these manufacturers are small firms.

In Nepal, for example, there are eleven turbine manufacturers with anywhere from four to twenty employees. Some of these firms are now exporting to neighbouring nations.

Rather than approaching this as competition, however, Canadian firms could establish partnerships with companies in developing countries thus enhancing the prospect for successful joint venture projects.

As the frequency of south-south trade increases, joint ventures will become an integral part of doing business in the Third World.

Is there a Canadian niche in all this?

Many exporting countries use their respective aid programs to "pull" the market for particular products and services. To a large extent, this has been the case with Third World small hydro projects developed by Americans, Europeans and, to the extent that CIDA has supported small hydro, Canada as well.

The result of this thrust is that few firms approach developing country marketing with an eye to creative financing. Canadian firms, for example, if they cannot interest CIDA in a project, assume there is no point in pursuing the matter further. Such is absolutely not the case. In fact, the place to start looking for project financing is in the country where you intend to develop your project.

But if Canadian firms lack creative financing experience the competition, in many cases, does not have a great deal more. This could leave a market niche open for Canadian entrepreneurs.

In fact, since Canada's aid agencies do not seem enthusiastic about small hydro, direct financing approaches, often involving private sector to private sector arrangements, may be the only way Canada's small hydro sector will be able to access developing country markets at all.

Certainly on an aid program against aid program comparison, Canadian small hydro firms will find it difficult to compete.

So more now about financing.

While successful export marketing requires time, commitment and organization, successful export financing depends on the seller's flexibility and capability to determine how best to develop a project in a particular country. There are no hard and fast rules. What works in one country, will not necessarily work in another.

LOCAL FINANCING

Many companies overlook the fact that the place to begin to identify project financing is in the country where the project is to be situated. This may not be as difficult as is often made out.

Conventional wisdom suggests that most Third World countries are considered too poor to pay for development projects without foreign aid. In fact, there is usually a considerable amount of entrepreneurial wealth available which can be marshalled to finance at least part of a project.

To illustrate this point it is useful to examine a sample project. We will assume that a client has been found for a small hydro project costing US$5 million. Assume also that the host country has serious currency restrictions -- i.e., the country's central bank limits the out-flow of hard currency.

The cost of civil works can usually be covered directly and without great difficulty by the buyer. If there is a requirement for imported components such as steel, there may be some difficulty with hard currency requirements. Local costs usually make up 25 percent of the total project costs and can be paid in soft currency (local funds). In most countries there is a certain amount of steel fabrication and assembly capability that can be employed on certain parts of a small hydro system. Local fabrication again means that payment is made in soft currency and therefore more easily paid by the buyer. The buyer might also have access to some of the basic materials locally. Of the total cost of the plant, local manufacture may save another 15 percent of hard currency requirements.

What about the seller's return? This is usually a further demand for hard currency. Here, an aggressive exporting company, confident in its equipment, might offer to take a small equity position (say 15 percent) for the initial five years of the project.

The selling company, that is to say you, will have cut the hard currency needs of the project from an initial 100 percent down to about 45 percent. Now you can approach the host country government and request that the remaining 45 percent be made available from the country's hard currency reserves. Convincing the host government will depend on the strength of the seller's case regarding such matters as import substitution, industrial development, rural electrification, and other issues relating to national economic benefits.

Other potential approaches include simple counter trade - i.e., goods for goods; debt swaps through banks, and so on.

The point is simply that funding can be found for almost any financially reasonable project. But one has to know exactly how much hard currency is going to be required from outside the country. In other words, how much help does one need from either the Canadian government or the international donor agencies.

CANADIAN FINANCIAL ASSISTANCE:

Any Canadian company trying to export equipment or services, pursuing a joint-venture relationship abroad, or wishing to sell technical knowledge, is a candidate for help from agencies of their provincial or federal government.
This help comes in a wide range of sophisticated packages from a number of different agencies.

In the case of provincial governments, the amount of money available is small and varies considerably from province to province. On the other hand, obtaining such funding is quite straightforward. Indeed in some provinces, because the provincial officials have better knowledge of local companies, application evaluations can be completed quickly.

For assistance with client identification, one can use the services of CIDA. CIDA funds only apply in developing countries which receive official development assistance from Canada.

For a "starter" study, CIDA's Industrial Cooperation Division will pay 100% of the actual costs of out-of-country visits up to a maximum of $15,000. These funds are not expected to be repaid by the Canadian company if it is successful in negotiating or completing a deal. These funds can only be accessed, however, if the Canadian company has already identified a potential joint venture partner and wishes to investigate the situation more thoroughly. Identifying a potential joint venture partner can simply mean having received a letter of interest from a developing country firm. Such letters often result from referrals to Canadian firms by the Canadian embassy in the country concerned.

CIDA also offers assistance in signing a contract through its Viability Study (up to $100,000.) and its Technology Transfer Facility (up to $500,000.). CIDA has a number of other programs which should be investigated by interested parties.

External Affairs funds through PEMD (Program for Export Market Development) are also available to cover half the cost of trade mission participation, visits outside Canada to identify markets or visits by foreign buyers to Canada, proposal preparation, the establishment of export consortia and/or the establishment of permanent sales offices abroad. The funding is repayable if a sale results from the support provided.

The ease with which one can obtain project financial assistance from within Canada depends to a large extent on the country where the project is to take place. The government of Canada has indicators that can be used when deciding whether or not to explore export opportunities in a particular country.

Financial Indicators

The Export Development Corporation (EDC) analyses the risk of doing business in all countries. This assessment estimates the probability of a given country paying its international debts to governments and private firms.

The availability of EDC export support programmes varies according to EDC's assessment of the risk. The more risk, the less help is available. Normally a company can discover if a specific country is considered too risky, or "off cover", by a direct request. EDC also publishes a list of countries which it assesses as good places to do business from a financial perspective.

The Canadian Superintendent of Financial Institutions (SFI). also offers an assessment of countries' ability to pay their debts.

The fact that a country is on the SFI list should concern an exporting company because the Superintendent requires that Canadian banks make a provision for losses equal to 35-45% of a negotiated loan.

Doing poorly on the EDC or SFI list does not mean a particular country should be discarded as a potential export market. Many developing countries qualify for bilateral development grants from CIDA or lines of credit from CIDA or EDC.

However, at this point let me make it quite clear that no company can base its export stategy on the assumption that work will come from CIDA. Either a company has a viable export product or it doesn't. Using CIDA services should add to the profitability of the export effort but not guarantee that profitability.

International Development Banks

The international banking system consists of the World Bank, the Asian Development Bank, the African Development Bank, the Caribbean Development Bank, and the Inter-American Development Bank. In addition there are other related organizations, such as the International Finance Corporation, which can be of assistance to exporters.

Funding a project through an international development bank is not an easy task unless the project arose from within the bank and is part of a bank programme.

For an independent sale, a Canadian company will have better opportunity for success if it approaches the section of the bank which deals specifically with the private sector. In Washington, this means the IFC or International Finance Corporation.

The IFC is active in financing private sector projects in the developing world. It normally only considers projects with at least $US20 million capital cost and will not take more than a 25 percent equity or loan position in a project. That is, it prefers to make loans of $5 million or more. If, however, several small projects were clustered together under one proposal and the total value of these combined projects was $20 million, then IFC would be interested. In addition to the 25 percent IFC will put into a project itself, it will also syndicate the rest of the financing for a well prepared project.

For projects smaller than $US20 million, IFC has two special facilities (other than "clustering" mentioned above) which can provide assistance for much smaller projects. Providing there are no government restrictions, the African Development Facility and the Caribbean Development Facility both structure projects and find financing for initiatives up to $US5 million. In fact, last year's annual report indicates that some projects were below $US500,000 and that IFC investment in equity or loans was as high as 50 percent of the project value.

What about private banks?
It is almost certain that approaching a Canadian bank will not be productive. Canadian banks have limited international trading experience and are generally not interested in international project financing unless the Canadian government provides solid guarantees.

It is often more effective to approach a foreign bank that does business in your client's country. For example, a French bank for Francophone Africa or the Hong Kong Shanghai Bank for South East Asia, or an Arab Bank for the Middle East.

CONCLUSION

With a careful choice of country, and a well analysed, financially viable and professionally presented project, it should be possible to finance almost any initiative. Failure is almost guaranteed in cases where the seller assumes that less time can be spent arranging the financing than was involved in identifying and selling the project in the first place. With imagination, courage and persistance, as well as a committment of some of the seller's own financial resources, sufficient hard currency can be identified for almost all projects you care to pursue.

The Market is there.

So is the Canadian capability.

Our niche is private sector to private sector joint ventures with developing country entrepreneurs.

Coupled with creative financing, small hydro can meet some of that enormous, developing country demand for reliable, cost-effective electricity.

Ontario Hydro's Activities in Small Hydro

By
Robert Franklin
Ontario Hydro

6

NOTES FOR REMARKS

ROBERT C. FRANKLIN
CHAIRMAN AND PRESIDENT
ONTARIO HYDRO

TO

SMALL HYDRO'88
CONFERENCE AND TRADE SHOW

JULY 6, 1988
HARBOUR CASTLE WESTIN
TORONTO, ONTARIO

Good morning, ladies and gentlemen. I'm delighted to join you and to be a part of Small Hydro '88. Bob Wong has graciously asked me to highlight for you some of the current goals and initiatives Ontario Hydro is pursuing in the area of small hydraulic development.

His invitation was one I gladly accepted for a number of reasons...but the main one...was to take advantage of the opportunity to tell you that Ontario Hydro expects "big" things from small hydro in the 1990s. We're counting on its successful development to help us meet the province's future electricity needs. And because we are counting on it, I'm especially pleased to outline and emphasize Ontario Hydro's new focus on small hydro.

Small hydro's importance to Ontario Hydro has become obscured of late by the tendency to see us exclusively as a developer of large-scale thermal power projects. Well, I'd like to set the record straight. Sure thermal sources like nuclear and coal are vital sources of electrical energy in this province, but they are by no means the only source. They never have and never will be.

ONTARIO HYDRO'S VERY NAME DENOTES A LONG HISTORY OF GENERATING POWER HYDRAULICALLY. WE WILL CONTINUE TO DO SO IN THE FUTURE. WE WILL CONTINUE OUR EFFORTS TO DO SO MORE EFFICIENTLY. AND, MOST IMPORTANT, WE WILL CONTINUE TO COOPERATE ACTIVELY WITH OTHERS WHO WANT TO DO IT AS WELL -- ESPECIALLY WITH PRIVATE SECTOR DEVELOPERS HERE IN ONTARIO AND WITH INTERNATIONAL CLIENTS AROUND THE WORLD.

AND SPEAKING FOR JUST A MOMENT ON THE INTERNATIONAL INTERESTS, YOU MAY NOT KNOW THAT ONTARIO HYDRO HAS BEEN WORKING WITH ELECTRICITY AUTHORITIES ON HYDRAULIC PROJECTS SINCE THE 1960S. IN GHANA, IRAN, NIGERIA, KENYA, AND BRAZIL FOR INSTANCE, WE'VE PROVIDED HYDRAULIC COMMISSIONING, TRAINING, AND OPERATIONS SUPPORT. AND IN AUSTRALIA, THE U.S. AND ELSEWHERE, WE HAVE BEEN INVOLVED IN DAM REHABILITATION PROJECTS, AND PROJECTS DIRECTED TOWARD THE LIFE ASSESSMENT AND RECONDITIONING OF HYDRO-ELECTRIC GENERATING STATIONS.

WE WILL BE DOING MORE OF THIS WORK IN THE FUTURE AND CURRENT PLANS SEE OUR POTENTIAL INVOLVEMENT WITH PROJECTS IN SPAIN, ZIMBABWE, MALAYSIA, INDONESIA AND TURKEY. OUR INTERNATIONAL CLIENTS HAVE NOT BEEN MISLEAD INTO THINKING OF US AS PREOCCUPIED WITH THERMAL STATIONS. AND I WANT TO MAKE SURE TODAY THAT YOU DO NOT RETAIN THAT IMPRESSION EITHER.

Our international experience has another dimension of more direct interest to you perhaps. It includes bringing Canadian small hydro companies together with international clients. For instance, last year we helped an Ontario manufacturer of small hydro equipment pursue business opportunities in Sri Lanka.

We were approached by consultants from Sri Lanka for information on alternative energy sources. When they outlined their needs, we put them in touch with a small hydro company here in the province. The company had no prior involvement in the export market, so we were able to provide direction to the company on how best to proceed.

They were successful in gaining the Sri Lanka business, and as such, have now been introduced to the small hydro equipment export market. This is a role, because of our knowledge and reputation for things hydraulic, we would like to play more often for Ontario's private sector companies and consultants.

At the provincial level, Ontario Hydro has been cooperating with and living alongside autonomous hydraulic generators for over 80 years. At present there exists about 1200 megawatts of power -- 5 percent of the province's total electrical capacity -- which is generated independently of Ontario Hdyro. And the bulk of this power comes from hydraulic and industrial cogeneration.

FURTHERMORE, WE ESTIMATE THAT AS MUCH AS 1000 MEGAWATTS OF ADDITIONAL POWER CAN BE DEVELOPED FROM PARALLEL GENERATION SOURCES BY THE YEAR 2000. AND AS MANY AS 400 OF THOSE MEGAWATTS COULD COME FROM SMALL HYDRO SOURCES.

JUST BEFORE I PURSUE THAT THEME, LET ME TELL YOU OF OUR OWN HYDRAULIC OPERATIONS. HYDRO CURRENTLY OWNS AND RUNS 68 HYDRAULIC STATIONS -- A TOTAL OF 264 INDIVIDUAL UNITS. COLLECTIVELY, THESE UNITS HAD A GENERATING CAPACITY OF 6500 MW IN 1987, REPRESENTING 25 PERCENT OF OUR ENTIRE POWER OUTPUT FOR THE SAME YEAR.

WHAT'S MORE, WE PLAN TO ADD SIGNIFICANTLY TO THAT OUTPUT BY MAXIMIZING THE EFFICIENCY OF OUR EXISTING WATER-POWERED PLANTS, MANY OF WHICH HAVE BEEN OPERATING FOR CLOSE TO 70 YEARS.

IN THE MONTHS AND YEARS AHEAD WE WILL BE EVALUATING THE CONDITION AND CAPABILITIES OF 34 OF OUR OLDER AND SMALLER STATIONS IN ORDER TO DETERMINE WHETHER THEY SHOULD BE REHABILITATED OR REDEVELOPED.

BY IMPLEMENTING THE FINDINGS OF THAT STUDY, WE EXPECT TO BE ABLE TO INCREASE THE TOTAL GENERATING CAPACITY OF THESE STATIONS BY MORE THAN 50 PERCENT, I.E., FROM 155 MEGAWATTS TO 263 MEGAWATTS.

WE ARE ALSO IN THE PROCESS OF STUDYING THE DEVELOPMENT OF WHOLLY NEW HYDRAULIC SITES AND THE REDEVELOPMENT OF OTHERS. OUR CURRENT PROGRAMS INVOLVING THE NIAGARA, LITTLE JACKFISH, AND MATTAGAMI RIVERS PROMISE TO MAKE AVAILABLE AN ADDITIONAL 1000 MEGAWATTS OF PEAK ENERGY BEFORE THE END OF THE CENTURY.

SO ONTARIO HYDRO IS VERY MUCH AN ACTIVE PLAYER IN THE HYDRO-ELECTRIC POWER BUSINESS. BUT WE'RE ONLY ONE PLAYER IN A FIELD THAT IS ATTRACTING MORE AND MORE PARTICIPANTS. WHICH BRINGS ME TO THE MAIN POINT I'D LIKE TO EMPHASIZE THIS MORNING.

WHILE WE HAVEN'T ALWAYS BEEN CREDITED WITH IT, HYDRO WELCOMES INCREASED PRIVATE SECTOR PARTICIPATION AND APPLAUDS THE EFFORTS OF THE MINISTRIES OF ENERGY AND NATURAL RESOURCES TO PROMOTE INDEPENDENT, SMALL-HYDRO ENTREPRENEURSHIP. WE BELIEVE SUCH EFFORTS WILL ULTIMATELY MAKE ONTARIO'S ECONOMY STRONGER AND MORE COMPETITIVE, WHILE AT THE SAME TIME, ENHANCE BOTH THE FLEXIBILITY AND CAPACITY OF ITS ELECTRICITY SUPPLY SYSTEM.

INDEED, WE HAVE A NUMBER OF INITIATIVES ON OUR OWN WHICH FOSTER SMALL HYDRO ENTERPRISE -- SOME OF WHICH I WILL BE SHARING WITH YOU IN A FEW MOMENTS.

ONTARIO HYDRO ALSO BELIEVES THAT IT IS PARAMOUNT FOR INDEPENDENT, SMALL-HYDRO ACTIVITY TO GO FORWARD IN SUCH A WAY AS TO GUARANTEE THE LONG-TERM INTERESTS OF OUR CUSTOMERS AND OUR SMALL HYDRO PARTNERS. TO REALIZE THIS OBJECTIVE, WE ARE ADOPTING A MORE PROGRESSIVE, PROACTIVE APPROACH TO SMALL-HYDRAULIC DEVELOPMENT -- AN APPROACH BASED ON COOPERATION WITH THE PRIVATE SECTOR AND GOVERNMENT AND OUR RESPONSIBILITY TO THE ELECTRICITY CONSUMERS OF ONTARIO. THAT'S WHY WE HAVE JUST ANNOUNCED THE CREATION OF A NEW NON-UTILITY GENERATION DIVISION AT HYDRO -- TO OPTIMIZE THIS SECTOR'S CONTRIBUTION TO THE ELECTRICAL SYSTEM.

THIS APPROACH WILL, IN MY ESTIMATION, OFFER ALL PARTIES CONCERNED A FAIR AND EQUITABLE OPPORTUNITY BOTH TO BENEFIT AND PROFIT FROM THE SEVERAL HUNDRED UNDEVELOPED OR ABANDONED SITES AVAILABLE IN ONTARIO TODAY. WHICH IS GOOD NEWS FOR THIS PROVINCE BECAUSE MANY OF THESE SITES RESPONSIBLY MANAGED, COULD ADD AS I SAY, AS MUCH AS 400 MEGAWATTS TO THE PROVINCIAL POWER GRID BY THE YEAR 2000.

SO LET'S GET DOWN TO SOME SPECIFICS. WHAT EXACTLY IS HYDRO GOING TO DO TO FACILITATE AND PROMOTE SMALL HYDRAULIC DEVELOPMENT IN THE PRIVATE SECTOR?

FIRST, WE WILL BE WORKING CLOSELY WITH THE MINISTRY OF NATURAL RESOURCES (MNR) TO HELP THEM ENSURE THE ORDERLY AND EFFECTIVE RELEASE OF GOVERNMENT SITES.

FOR SITES WHOSE POTENTIAL CAPACITY IS 5 MEGAWATTS OR LESS, HYDRO WILL CONTINUE TO PLACE AT THE MINISTRY'S DISPOSAL, OUR REVIEWS OF SITE APPLICATIONS SUBMITTED BY PRIVATE SECTOR PROPONENTS. THESE REVIEWS AID IN DETERMINING THE MERIT OF A PARTICULAR PROPOSAL BY EVALUATING SUCH ITEMS AS THE PROJECT'S CAPABILITY WITH EXISTING OR PLANNED DEVELOPMENTS ON THE SAME WATERSHED; AND BY ASSESSING THE PROJECT'S OVERALL FEASIBILITY, PARTICULARLY AS AFFECTED BY THE ELECTRICAL CONNECTION TO THE POWER SYSTEM.

WHEN IT COMES TO THE RELEASE OF SITES ABOVE THE 5 MEGAWATT LEVEL, WE ARE PREPARED TO WORK EVEN MORE CLOSELY WITH THE MINISTRY, ESPECIALLY IN THE AREAS OF CALLS FOR PROPOSALS, BID EVALUATIONS, AND THE POWER PURCHASE CONTRACT.

FOR INSTANCE, PRIOR TO A CALL FOR PROPOSALS, WE WOULD BE WILLING TO ASSIST MNR WITH A STUDY OF THE PARTICULAR RIVER SYSTEM UNDER CONSIDERATION, IN ORDER TO IDENTIFY THE MOST EFFICIENT WAYS TO DEVELOP THE WATERSHED FOR SMALL HYDRO GENERATION. WE WOULD REVIEW OUR POWER SYSTEM, TO TARGET THE BEST LOCATIONS FOR ELECTRICAL CONNECTIONS. AND WE WOULD ALSO DRAW UPON OUR OWN SITE DEVELOPMENT EXPERIENCE IN THE AREA, TO HELP MNR PINPOINT THE MOST FAVOURABLE SITES.

EQUALLY IMPORTANT, WE WILL COOPERATE WITH MNR IN SETTING UP SPECIFIC BID EVALUATION CRITERIA TO MAXIMIZE THE CHANCES OF A PROPOSED PROJECT'S SUCCESS. WE WOULD SUGGEST THAT THESE CRITERIA WOULD PLACE AN EMPHASIS ON THE ASPECTS OF THE PROPOSED DEVELOPMENT -- THE TECHNICAL AND FINANCIAL ASPECTS, RESOURCE UTILIZATION, ENVIRONMENTAL, AS WELL AS THE COMPATIBILITY OF THE PROJECT WITH OTHER USERS ON THE WATERSHED.

AND FINALLY, WE WILL WORK WITH MNR TO FORMULATE INTO THE CALLS FOR PROPOSALS, PROCEDURES WHICH EFFECTIVELY BIND TOGETHER BOTH THE DEVELOPER'S SITE-BID (MADE TO THE MINISTRY) WITH THE POWER-PURCHASE BID THAT IS MADE TO HYDRO.

UNITING THE TWO PROPOSALS -- WHICH UP TO NOW HAVE BEEN SEPARATE -- CERTAINLY MAKES A GREAT DEAL OF SENSE. OTHERWISE WE COULD EASILY CREATE A SITUATION WHERE A SMALL HYDRO DEVELOPER GETS AWARDED A SITE BY MNR, BUT FAILS TO REACH A SATISFACTORY AGREEMENT WITH ONTARIO HYDRO ON THE PRICE OF THE POWER THAT WILL BE PRODUCED. A CLASSIC CASE OF BEING ALL DRESSED-UP WITH NO PLACE TO GO. COMBINING THE SITE-BID WITH THE POWER-PURCHASE BID WILL THEREFORE ELIMINATE THIS UNDESIREABLE SITUATION.

AS FAR AS HYDRO'S RELATIONSHIP WITH THE PRIVATE SECTOR GOES, WE WANT IT TO BE BASED ON BUSINESS-LIKE COOPERATION AS WELL. WE SEEK MUTUALLY BENEFICIAL PARTNERSHIPS WITH SMALL HYDRO DEVELOPERS AND CONTRACTORS. AND WE ARE WILLING TO GO TO CONSIDERABLE LENGTH TO GET THEM ESTABLISHED -- PARTICULARLY WHERE LARGER HYDRAULIC SITES ARE CONCERNED.

THIS IS PART OF OUR NEW FOCUS ON SMALL HYDRO DEVELOPMENT AND I WANT TO STRESS THAT WE ARE PREPARED TO ENGAGE IN SOME CONSTRUCTIVE GIVE AND TAKE IN OUR DEALINGS WITH INDEPENDENT DEVELOPERS. IN THE PAST, OUR SUPPORT WAS PROBABLY TOO "RULE-BOUND." WELL, WE STILL HAVE IMPORTANT REQUIREMENTS TO ADHERE TO, CONCERNING THE OPERATION OF THE SYSTEM, BUT WE ARE TRYING TO BE MORE OPEN TO NEW WAYS OF DOING BUSINESS.

I CAN PICTURE A NUMBER OF CASES, FOR INSTANCE, WHERE HYDRO AS THE OWNER OF A LARGE SITE WOULD BE VERY COMFORTABLE WITH THE IDEA OF HAVING A PRIVATE DEVELOPER COME IN, DO THE ON-SITE DEVELOPMENT AND CONSTRUCTION WORK, AND OPERATE THE FACILITY.

IN MATTERS OF SMALL HYDRAULIC DEVELOPMENT, THE WATCHWORD AT ONTARIO HYDRO WILL BE "FLEXIBILITY." WE ARE COMMITTED TO ENCOURAGING PRIVATE SECTOR PARTICIPATION IN THIS AREA. AND WE ARE WILLING TO EXPLORE ALL REASONABLE OPTIONS TO BRING ABOUT THIS PARTICIPATION.

AND THAT INCLUDES FLEXIBILITY IN THE PURCHASE RATES WE OFFER TO SMALL, INDEPENDENT HYDRO PRODUCERS. WE WELL APPRECIATE THE GROWING CONTRIBUTION THIS AND OTHER KINDS OF PARALLEL GENERATION ARE MAKING TO THE ENERGY NEEDS OF THE PROVINCE. AND AS LONG AS OUR PURCHASE RATES DO NOT DISADVANTAGE OUR CUSTOMERS, WE WOULD LIKE TO SEE THEM REFLECT SMALL HYDRO'S INCREASING LONG-TERM VALUE AS A POWER SYSTEM RESOURCE.

I BELIEVE THESE KINDS OF INITIATIVES AND ATTITUDES DEMONSTRATE ONTARIO HYDRO'S WILLINGNESS TO ADOPT FLEXIBLE, POSITIVE, AND PROGRESSIVE ARRANGEMENTS WITH THE PRIVATE SECTOR ON A VARIETY OF SMALL HYDRAULIC ISSUES.

I BELIEVE WE CAN AT THE SAME TIME, BALANCE OUR COMMITMENT TO SMALL HYDRO WITH THE LONG TERM INTERESTS OF OUR CUSTOMERS, SO THAT OUR APPROACH TO SMALL HYDRAULIC DEVELOPMENT IS RESPONSIBLE TO ALL ONTARIANS.

THAT RESPONSIBILITY IS -- AND ALWAYS WILL BE -- TO FURNISH POWER AS CHEAPLY AS POSSIBLE TO ALL OUR CUSTOMERS...TO GUARANTEE THEM A SUFFICIENT, RELIABLE, AND SAFE SUPPLY OF ELECTRICAL ENERGY...AND TO ENSURE THAT THESE BENEFITS CONTINUE TO BE PROVIDED ON A LONG-TERM BASIS.

SMALL HYDRO DEVELOPMENT, PROPERLY MANAGED AT THE BOTH THE PUBLIC AND PRIVATE LEVELS, CAN HELP FULFILL THIS MANDATE. AFTER ALL IS SAID AND DONE, HYDRO-ELECTRIC POWER REMAINS ONE OF OUR MOST PRIZED FORMS OF ENERGY. IT'S BASED ON AN INDIGENOUS RESOURCE. AND WHILE IT'S NOT WITHOUT FAULTS, IT'S A CLEAN, SAFE WAY TO MAKE ELECTRICITY. AND THE STATIONS WHICH USE IT LAST FAR LONGER THAN ANY OTHER KIND OF POWER FACILITY.

BY EXPLOITING THIS RESOURCE WISELY AND RESPONSIBLY, THE SMALL HYDRO ENTREPRENEUR WILL ASSUREDLY MAKE A VALUABLE CONTRIBUTION TO THE ENERGY REQUIREMENTS OF THIS PROVINCE AND ITS PEOPLE...BOTH NOW AND FOR DECADES TO COME.

PETER HAINES URGED YOU NOT TO GIVE UP -- THIRD WORLD COUNTRIES NEED YOU. I URGE YOU NOT TO GIVE UP TOO. ONTARIO NEEDS YOU. AND ONTARIO HYDRO NEEDS YOU TOO.

-30-

Banquet Keynote Address

By
Honourable Robert C. Wong
Minister of Energy

NOTES FOR REMARKS BY

ROBERT C. WONG
ONTARIO MINISTER OF ENERGY

AT THE

SMALL HYDRO '88 CONFERENCE

HARBOUR CASTLE WESTIN HOTEL, TORONTO
THURSDAY, JULY 7,1988
6:00 P.M.

CHECK AGAINST DELIVERY

Good evening ladies and gentlemen, and thank you for such a complimentary introduction, Vince.

It is a great honor to have a chance to address so many distinguished guests from around the world.

And I'm pleased to be able to speak to you about one of Ontario's most important natural resources: water.

Tonight I'd like to talk to you about Ontario's experience with small hydro.

- I'll talk about how water power has served our people in the past, and how it fits into the picture today.
- And I'll also explain why we are intent on making it a continuing part of our future.

And I'd like to start by telling you a typical story from Ontario's past, about one of our old water mills.

The Charlton Mill -- which stands on the shore of Long Lake, in Charlton -- is about 475 kilometers northwest of here.

The site began as a sawmill at the turn of this century -- and of course, water power was used to operate it. Later the Charlton site was developed into a small hydro plant.

You have to understand that, at the turn of the century, Charlton was a booming, Northern Ontario frontier town. It was the end of the railway line for gold miners and prospectors heading into the bush country, and an important centre for the forest industry.

Charlton was the commercial hub of the region -- and the small hydro mill was providing the power that made the local economy go.

Unfortunately, the town's prosperity was short-lived. In just one day -- October 4, 1922 -- The Great Fire of Northern Ontario raged across vast areas of farmland and bush, destroying everything in its path.

Whole towns and villages went up in smoke.

The residents of Charlton panicked, as almost every building in town fell in flames. Many fled, and 44 died.

When the fire was at its height, about 70 people sought refuge in the mill, which of course was located by the water. As the flames destroyed the town, those 70 people huddled together in the safety of the mill.

During that terrible night, a baby was actually born inside the mill.

The Great Fire destroyed the town of Charlton, and more than six million acres of farm and woodland. But the mill had a life of its own.

Years after the Great Fire, the Charlton site was re-developed -- this time as a grist mill. In the mid-sixties, there was another fire. And this time, all that remained was a gutted foundation and the concrete floor.

In 1982, the Charlton Mill was designated as a historical landmark. You might think this is the end of the story, and that the mill has become some kind of quaint museum.

But in fact, the Ministry of Natural Resources is making arrangements with a private developer to redevelop the Charlton site once again -- for small hydro power.

I tell you this story for a couple of reasons.

First, the water power that has given the Charlton site such a long life is one of Ontario's most useful and productive resources.

Second, there are literally hundreds of mills like Charlton in Ontario. Water power has played a very important part in our history, and in our economic development.

Third, and most importantly, our experience with hydro power over the years is extensive. And that experience means we can offer specialized knowledge, skills and equipment that can be very useful in a world that needs electric power.

Now, I have spent several minutes talking about an event that happened more than 60 years ago. I want to take just a few moments more to bring you up to date on the small hydro story in Ontario.

From 1900 to the present, Ontario has always been a society that hungers for energy.

More than 80 years ago, we had not yet tapped the great reservoir of power at Niagara Falls. Even worse, we had sold out to United States power companies -- developers who were looking to control the entire output of Niagara Falls.

Ontario's only large-scale electricity option seemed to be to produce power from imported coal, and to continue to rely on hundreds of small hydro sites scattered across the province, primarily to meet local needs.

However, in 1902, the people of Ontario experienced their first energy crisis: Coal miners down in Pennsylvania went on strike, and we had to purchase coal from Wales.

And we had to pay three times the normal price.

Before too long, a group of Toronto businessmen got interested in developing the Canadian side of Niagara Falls for large-scale electricity production.

Of course, they were interested in making a profit. But they had to contend with a growing movement in support of a publicly-owned electricity utility.

The driving force behind this crusade was the Mayor of our City of London, Adam Beck, who campaigned fereventl for the creation of a public hydroelectric utility for Ontario.

And in 1906, the Ontario government bowed to public pressure. It passed legislation creating the Hydro-Electric Power Commission of Ontario, which later became Ontario Hydro.

Adam Beck's vision and his accomplishment earned him a knighthood. And today, the Sir Adam Beck plant in Niagara Falls produces 1,566 megawatts of power

As many of you know, Ontario Hydro is one of the world's largest and most respected public utilities. It's total assets are in the billions -- and its total generating capacity is more than 30-million kilowatts.

Over the years, the growth of Ontario Hydro sounded the death knell for many of our small hydro sites.

It was a matter of simple economics. It became cheaper to build large generating stations, all linked to a central grid.

At the same time, we grew more dependent on relatively cheap oil and gas to meet the rest of our energy needs.

The system we have today is large, even by international standards. It incorporates thermal nuclear, thermal coal, cogeneration and other sources.

But -- as the name itself suggests -- Ontario Hydro is built on water power. And water power still plays a very important role in our province today.

Just 20 years ago, this conference would not have been possible. At that time we didn't pay much attention to our small hydro potential.

In most other parts of the world, it was the same story: Where people thought about electricity, most of them were thinking big -- mega projects, which cost mega dollars.

In Ontario, we were moving ahead with our large coal-fired and nuclear programs. Around the world, there was the Saad al-Ail Dam on the Nile; Ghana's Akosombo Dam and the Tarbeka Dam in Pakistan.

The answer to increasing demand the world over was always the same: build more and bigger plants, and buy as much cheap oil as you can.

For all of us, the era of cheap oil ended dramatically in the early 1970s.

All around the world, nations moved quickly to adjust their energy supplies and strategies. Ontario, too, took measures to diversify our energy supplies.

We sought to minimize our dependence on any one source. And almost overnight, we re-discovered the benefits of small hydro.

Since then, our small hydro industry has experienced rapid growth, spurred on by government encouragement programs.

Our efforts have led to the development of a number of small hydro sites. And Ontario Hydro is currently negotiating 27 development proposals, representing a total of more than 120 megawatts.

These activities represent more than one-quarter of a billion dollars of economic activity.

And that brings us more or less up to date. But what about the future of Small Hydro?

Simply put, the future looks very positive. We believe that small hydro can play a role in our future growth -- as a secure source of energy, and as an export industry we can expand.

I think the fact that we are sponsoring this conference is an indication of just how important we think small hydro can be.

You've come to the right place for a conference on water power. If you look at a map of Ontario, you'll see that half of it is blue.

To many of our private small hydro developers, that blue also represents the potential for future growth and prosperity.

We are committed to developing all the economically feasible small hydro sites we can. But this development will take place on the basis that our water resources and a clean environment are also vital to our future well-being.

Many of our future hydro developments will be in the North, where the environment is particularly susceptible to damage. As one former Minister of Northern Affairs once said: "There are places in Northern Ontario where the hand of man has never set foot."

I'm not sure exactly what he meant, but I think he was absolutely right.

Today -- and in the future -- we plan to work hand in hand with communities across the North, and with Vince Kerrio and his staff, to ensure that small hydro developments are economically atractive, and environmentally sound.

As all of you know by now, small hydro has a lot to offer.

New capacity can be developed with shorter lead times and lower capital costs than those required for central generation.

No external fuels are required, and this is particularly important to Ontario, where we buy more than 80 per cent of our energy requirements from outside the province.

Perhaps most importantly, small hydro does not come with a large environmental price tag. It is a safe and sensible alternative, based on a proven, highly economical technology.

In a province with a very large, world-class public utility, there is ample room for private small hydro development. Their involvement generates new jobs and more tax revenues. It can also play an important role in diversifying our sources of supply.

Small hydro helped Ontario to enter the industrial revolution. Now it is helping us make the transition to a post-industrial society.

For many of you here tonight, our past could be your future.

As I am sure you have seen during this conference, Ontario has a wealth of experience producing hydro power -- often under the roughest conditions, in remote areas, in a harsh climate, in the bush and in agricultural areas.

Many of you here tonight come from places that pose equally difficult challenges. And some of you come from nations burdened by high, imported energy costs, high debts, and little or no foreign exchange.

If you have indigenous water resources, small hydro can be an effective catalyst for industrial development. Your rivers and streams can provide power to communities who need it -- at a reasonable cost to the economy, and at no cost to the environment.

We have invited you here in the hope that you can share in -- and benefit from -- our century of experience with hydro power.

Because of our long history with hydro power, we in Ontario tend to to take electricity for granted. It is hard for most of us to imagine that 90 per cent of the world's population does not have access to reliable electricity supplies.

As you heard Mr. Jeff Passmore say yesterday, the international small hydro market has tremendous potential. And our private power sector is becoming increasingly interested in that market, as a place where it can contribute expertise and equipment.

Many of our consulting, engineering and manufacturing companies are represented here tonight, and I have a simple message for them.

Ontario's expertise is tremendous -- but international competition for small hydro goods and services is stiff.

I have another message for our out-of-province guests:

The companies at Small Hydro '88 are recognized as world leaders in small hydro technology. I believe Ontario's firms have earned a place at this table.

Through conferences such as this one, the Government of Ontario is helping to promote and match our expertise with the needs of the international market.

This conference is a forum for people to exchange ideas and make new contacts. And, if our own small hydro industry can do a little more business, so much the better.

Ontario experts aren't the only ones we have here. Manufacturers from a number of countries are well represented. And I hope that those of you from outside the country are taking the opportunity to meet with everyone, and to get the information you came for.

I want to conclude here tonight by telling you that I am very proud of Ontario's achievements with small hydro, both past and present.

And I appreciate the fact that you have shown such a great interest in our abilities.

I believe our shared knowledge, our past and present experiences, and our mutual commitment to small hydro technology, can bring the benefits of reliable power, and the economic growth that goes with it, to the millions of people around the world who need it.

And surely that is a very worthwhile goal.

Thank you.

-30-

SESSION 1:

UTILITY, ECONOMICS AND CONTRACTS

Chairperson: R. Dodokin
Waterpower Association of Ontario

Canadian Utility Policies and Private Generation

By
L.A. Gregoris, J. Lang, L. Moore

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CANADIAN UTILITY POLICIES ON PRIVATE GENERATION

PRESENTED AT SMALL HYDRO '88
JULY 6, 1988

Laurie Anne Gregoris
John Lang
Laurence Moore

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CANADIAN UTILITY POLICIES ON PRIVATE GENERATION

ABSTRACT

The purpose of this paper is to provide up-to-date comparative information on the private generation policies of 10 major Canadian utilities, as well as to examine emerging trends and changes in utility policy across Canada. This survey was done to provide information for potential private generation investors/developers, manufacturers of electrical equipment, utilities, government and regulatory boards.

The power purchasing policies of electrical utilities play a key role in determining the success of private generation development. With some exceptions the electrical utilities across Canada are large public agencies that differ greatly in terms of their sources of power, their rate structure, and their surplus or need for capacity. It is these differences which in turn affect each utility's policy on the purchase of private power.

The Ontario Ministry of Energy has documented electrical utility policies across Canada relating to the purchase of private power. In 1981 and 1985 surveys were conducted examining major areas such as, the right to interconnect, the right to wheel power, purchase rates, charges and metering. The survey was repeated again in 1987 to update the information database.

INTRODUCTION

Private generators have been operating for many years in several provinces. Recently there has been a recognition that private power can play a more central role in providing a diverse and flexible source of generation to utilities. During the late 1970s utilities began developing explicit policies to allow private power to play a larger role. The goal for most jurisdictions is to meet future electricity needs in a way that minimizes long term costs while at the same time ensuring that the impact on the environment and on society is small. Private generation policies should further this overall goal.

This paper documents the Ontario Ministry of Energy's Canada-wide survey of electrical utility policies relating to the purchase of private or independent power.

In 1981 and 1985 surveys were conducted examining major areas such as, the right to interconnect, the right to wheel power, purchase rates, charges and metering. The survey was repeated again in 1987 to update the information database, and to provide up-to-date comparative information on the private generation policies of 10 major Canadian utilities, as well as to examine emerging trends and changes in utility policy across Canada. (Refer to Charts 1 and 2).

UTILITY POLICIES

Newfoundland Light and Power Corporation Limited

Newfoundland Light and Power does not at present have formally approved policies covering all aspects of private generation. However, survey responses were based on the general direction that Newfoundland Light and Power felt such policies would take if such a policy was to be approved. In Newfoundland grid connection criteria are established by the utility and private generators are permitted to connect to the electrical grid and to sell power to Newfoundland

Light and Power. Currently the utility purchases electricity from Newfoundland and Labrador Hydro as well as from the Edward Duffy 1.5 kW wind turbine. Newfoundland Light and Power expects that the purchase rates that it will offer other generators in future will be based upon approved purchase power rates for firm energy from Newfoundland and Labrador Hydro and for secondary energy from Deer Lake Power Company Ltd. which is interconnected to Newfoundland and Labrador Hydro. These rates are expressed in /kWh and include appropriate allowances for capacity. Only two party wheeling is allowed, with charges based on the proportionate cost of facilities being used. Newfoundland Light and Power does not give special consideration for renewable forms of generation, large sources or high capacity factor private generators. Purchase rates are uniform throughout its jurisdiction and no limit is placed on the total amount of private power purchased.

Nova Scotia Power Corporation

Nova Scotia Mines and Energy Minister announced May 19, 1988 that the government will be directing the Nova Scotia Power Corporation to solicit proposals from private power producers to supply up to 30 MW of electric generating capacity to be made up of a number of individual projects. The Nova Scotia government believes that this policy will provide opportunities for all renewable sources of electrical generation (i.e. woodchip, small hydro) as well as contribute to the province's future energy mix. In order to facilitate the implementation of this new policy the Minister also announced that the Board of Commissioner of Public Utilities will be asked to establish the price paid for private power based on the avoided costs of the Nova Scotia Power Corporation. Nova Scotia Power under its own initiative is currently reviewing its policy on private generation, and hopes to have a new policy in place before the end of 1988. As a note of interest the utility has not made any changes in its private generation policy since the Ministry of Energy's 1985 survey. The rate paid for energy from a hobby size generator of less than 10 kW is still 6.27 /kWh which is based on the residential end rate. For generators in the 10 kW - 15 MW range, the rate is 70 per cent of the hourly marginal. For a 250 kW installation, this is set monthly at 1.9 /kWh. For any facility greater than 15 MW the rate is negotiated between the Nova Scotia Power Corporation and the private generator.

New Brunswick Electric Power Commission

Interconnection with the grid is permitted by the New Brunswick Electric Power Commission. The rate paid for energy to a private generator varies monthly. In 1987, the rate paid varied from 1.82 /kWh to 2.78 /kWh with an average of 2.25 /kWh. Rate calculation for dedicated supply (customer has no load and delivers total net production to New Brunswick Power) is 70 per cent of the monthly average hourly incremental cost. For surplus energy supply (the customer only sells surplus energy after meeting their own needs) the rate is calculated at 59.5 per cent of the monthly average hourly incremental cost. Currently, special consideration is not given for renewable forms of generation, large sources or high capacity factor private generators. Purchase rates are uniform throughout New Brunswick Power's jurisdiction. No set annual limit is placed on the amount of private power purchased. New Brunswick Power does not enter into multi-year purchase contracts at fixed or agreed upon rates. New Brunswick Power does not at present offer a blended rate nor any payment for capacity, however, purchase rates are currently under review.

Hydro Quebec

Sales of private power were essentially not allowed in Quebec up until recently. Hydro Quebec now has in place an approved private generation policy. Grid connection criteria are established by the utility and an individual is now permitted to interconnect to the grid to sell power. Wheeling is not allowed. Hydro Quebec offers a blended rate of 2.86 /kWh, however, the load factor must be greater than 75 per cent during the months of December, January, February and March, otherwise seasonal rates are employed. The seasonal rates are 3.78 /kWh from December to March and 1.71 /kWh for the remaining months. Rate calculation is based on avoided cost adjusted for system loss. Bi-directional energy metering is required, and the utility pays the costs for metering. Hydro Quebec enters into multi-year purchase contracts at fixed or agreed upon rates, with a maximum term of twenty years.

Ontario Hydro

In Ontario, an individual is permitted to interconnect to the grid to sell power to Ontario Hydro. Ontario Hydro has an established rate structure which in 1987 paid 3.6 /kWh for electricity produced at a high capacity factor of 65% or more by non-utility generators. This is more than the short-term avoided cost of approximately 2.0 /kWh, and closer to the long-term avoided cost of around 3-5 cents/kWh (range is dependent on the choice of options in the future). A lower rate of 2.54 /kWh is paid if the capacity factor is less than 65%. A 4.94 /kWh rate is available as a ten year fixed rate for renewable resources. For parallel generators capable of delivering 350 kW or more, a time differentiated payment schedule is available, with higher payments during the winter and during peak hours. The rate paid for purchased power reflects long run avoided costs and is currently based on 85 per cent of the average cost of power for high capacity factors and 65% or the average cost of power for low capacity factors. Ontario Hydro will wheel power for a private generator to another service in Ontario owned by the generator. Wheeling charges for the Retail Distribution System (less than 50 kilovolts) are:

up to 20 kilometers	0.035 per kW per kM
over 20 kilometers up to 40 kilometers	0.7 per kWh
over 40 kilometers	1.41 per kWh

Wheeling administration charges are also levied. (Refer to Appendix A). The utility enters into multi-year purchase contracts at fixed or agreed upon rates. The maximum contract term is 20 years. No annual limit is placed on the total amount of private power purchased by Ontario Hydro.

Manitoba Hydro

In Manitoba, an individual is permitted to interconnect to the grid to sell power to Manitoba Hydro. The energy produced by a private generator is credited against the energy consumed by the customer. The rate paid for energy by Manitoba Hydro to a private generator varies depending on the size of the installation involved. For a generator producing less than 20 kW there are two separate categories. A residential customer (as in rural farm installations) is paid at the residential end rate of 3.836 /kWh. A general service customer (non-domestic customer) is paid at the general service end rate which is 4.336 /kWh. No blended rates are offered, nor is payment for capacity made. Two and three party wheeling is not extended to private generators at this time. Purchase rates are uniform throughout Manitoba Hydro's jurisdiction. Currently no special consideration is given for renewable forms of generation, large sources or high capacity factor generators. Manitoba Hydro does not place an annual limit on the total amount of private power purchased, nor does it enter into multi-year purchase contracts at fixed or agreed upon rates.

Saskatchewan Power Corporation

In Saskatchewan, generators are permitted to connect to Saskatchewan Power's electrical grid system. Connection criteria are established by the utility. A blended rate is offered and is applicable to contracts in the 1 to 100 kW range. Energy payments alone are offered to contracts in the 101 to 10,000 kW range. A separate energy rate and capacity rate is offered and is applicable to contracts in the 10,001 to 50,000 kW range.

Rate calculation is based upon costs of future generation: average cost of power for smaller generators; proxy plant method for larger generators (above 10,000 kW). At the time this survey was taken actual rates had not been calculated as this is a recently developed rate structure. An annual limit is placed on the total amount of private power purchased by Saskatchewan Power. The limit is related to the annual growth in system demand. The current limit is set at 50 per cent of the forecasted growth in system demand, and is subject to change. Saskatchewan Power does enter into multi-year purchase contracts at fixed or agreed upon rates for a maximum contract term of 30 years.

Alberta Power Limited and TransAlta Utilities Corporation

There has been a growing interest in non-utility owned small power production in the province of Alberta, since the early 1980s. Pressure has been exerted by the Small Power Producers Association of Alberta, potential private power producers and various other lobby groups to develop a policy for private generation. On April 9, 1987 an Order in Council was issued requesting that a public inquiry be held by the Public Utilities Board (P.U.B.) and the Energy Resources Conservation Board (E.R.C.B.). The two Boards were to inquire into matters respecting: the size and type of generators that should be classified as small power generators; the number, types and capacities of small power generators and their total capacity that could be interconnected without negatively impacting the system; and the principles and methods which should apply to the setting of a price or prices which could be paid by public utilities for electricity produced by small power generators. The P.U.B. and the E.R.C.B. submitted a report outlining their findings and recommendations to the Alberta government February 1988. The Boards' recommendations are as follows:

o "generators having the capability of delivering 2500 kW or less at one site and one interconnection point be classed as small power generators;

o that a total of 100 MW of nameplate capacity could be interconnected without negatively impacting the reliability of the system or without substantially increasing the cost of electric service to consumers if priced in accordance with the principles and methods recommended by the Board;

o that the price to be paid for small power generation be based on long-term utility avoided costs, that there be separate prices for firm and as available power, that levelized prices be used for each of the above for 10, 15 and 20 year contracts, and that prices paid for such generation be uniform throughout the province, including contractual terms and conditions;

o that following adoption of a policy on small power by the Alberta government, the P.U.B. approve standard contracts between public utilities for small power production."

A new private generation policy was announced June 14, 1988 by the Alberta government in response to the P.U.B. and E.R.C.B. report. The Small Power Research and Development Program applies to generation from power from renewable sources. Under the Program, private developers of small hydro, wind and biomass projects will be able to contract with utilities at 5.2 per kilowatt hour. Projects of up to 2.5 MW nameplate capacity are eligible. The Research and Development Program will be available for up to 125 megawatts of capacity. The program terminates at the end of 1994.

British Columbia Hydro

British Columbia Hydro has had a private generation policy since 1981 to purchase power from its customers and private suppliers on the integrated system at the trailing step of the applicable retail or selling rate. The utility has not entered into any new purchase agreements due to a surplus of firm energy and capacity in recent years. British Columbia Hydro expects the surplus to last for another two or three years, and is currently working on a revised purchase policy that could allow the utility to purchase power during surplus conditions. Calculation of rates under the new policy would be based on the short term marginal value of power. The 1988 residential end rate is 4.47 /kWh. Special consideration is given to high capacity factor private generators in the form of a higher rate payment. Two and three party wheeling is not currently allowed by the utility. British Columbia Hydro offers private generators in remote diesel communities a "Share the Savings" rate which is based on fuel and lube oil savings.

CONCLUSIONS

We live in a country blessed with an abundance of diverse energy sources - natural gas, petroleum, coal, uranium, water, wind, biomass, solar and others. The 1987 survey on Canadian Utility Policies on Private Generation indicates that Canada is cautiously entering into an era of diversified energy sources. The fact that nine of the ten utilities surveyed in 1987 now have private generation policies actively in place indicates that the advantages of private generation are being recognized.

A positive trend emerges when one looks at the results of the survey. Several of the utilities are amidst revising their private generation policies, or have just recently put a new policy in place. In 1985 Hydro Quebec did not have a policy regarding private generation, it is only recently that the utility has allowed the sale of private power, thus acknowledging the benefits of private generation. Nova Scotia Power is undergoing a review of its private generation policy and hopes to have a new policy active before the end of 1988. The government of Nova Scotia has given the private power industry in their province a boost by directing Nova Scotia Power to solicit proposals from private power producers to supply upto 30 MW of electric generating capacity. This will provide opportunities for renewable sources of private generation (i.e. woodchip, small hydro). The province of Alberta has recently undertaken a public inquiry with a view to developing a new private generation policy. The new policy was recently adopted and it is very supportive of private electricity production from renewable sources. British Columbia has not entered into any new private power purchase agreements due to a surplus of firm energy and capacity; however, they are currently working on a revised purchase policy that could allow the utility to purchase power during surplus conditions.

The high level of activity in private generation policy indicates that the environment for private power generators is improving. Many of the policy revisions mean improved purchase rates for private generators, for example New Brunswick Electric Power is currently reviewing its purchase rates; Ontario Hydro has a new rate of 4.94 /kWh available as a ten year fixed rate for renewable resources; Saskatchewan Power now offers a blended rate with payment for capacity whereas in 1985 it did not.

A positive environment exists for private power in Canada, one that recognizes the advantages of private generation, and makes an attempt to encourage a more active private power industry.

UTILITY POLICIES ON PRIVATE GENERATION 1987/88

Chart 1

UTILITY	RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED RATE	PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
NEWFOUNDLAND LIGHT AND POWER CO. LTD.	YES	2 3 PARTY YES NO	PROPORTIONATE COST OF FACILITIES BEING USED	TIED TO PRICE PAID TO NFLD /LABRADOR HYDRO FOR FIRM POWER	NO	YES	EXPECTED TO BE BASED ON APPROVED PURCHASE POWER RATES FOR FIRM ENERGY FROM NFLD & LABRADOR HYDRO AND SECONDARY ENERGY FROM DEER LAKE POWER RATES INCLUDE APPROPRIATE ALLOWANCES FOR CAPACITY	6 130 CENTS/KWH	2 METERS 1 BUY 1 SELL	GENERATOR PAYS ALL COSTS OVER A NORMAL INSTALLATION
NOVA SCOTIA POWER CORP	YES	2 3 PARTY NO NO	N/A	AVOIDED COST (FOR 30MW RENEWABLES)	NO	NO	TO BE DETERMINED	6 27 CENTS/KWH	2 METERS 1 BUY 1 SELL	UTILITY PAYS FOR 1 METER, INSTALLATION AND READING, CUSTOMER PAYS FOR WHAT IS NOT USUALLY NEEDED
NEWBRUNSWICK ELECTRIC POWER COMMISSION	YES	2 3 PARTY NO NO	N/A	DEDICATED 70% OF MONTHLY AVERAGE HOURLY INCREMENTAL COST SURPLUS-TO-NEED 55% OF MONTHLY AVERAGE HOURLY INCREMENTAL COST PURCHASE RATES ARE UNDER REVIEW	NO (UNDER REVIEW)	NO (UNDER REVIEW)	YES RATE VARIES MONTHLY. IN 1987 1 82 CENTS/KWH TO 2 784 CENTS/KWH AVERAGE OF 2 25 CENTS/KWH	4 27 CENTS/KWH	IMPORT/EXPORT METERING	PRIVATE GENERATOR PAYS FOR ANYTHING NOT USUALLY REQUIRED
HYDRO QUEBEC	YES	2 3 PARTY NO NO	N/A	AVOIDED COST ADJUSTED FOR SYSTEM LOSS	YES 2 86 CENTS/KWH LOAD FACTOR MUST BE >75% DEC - MARCH, OTHERWISE USE SEASONAL RATE OF 3 78 CENTS/KWH DURING OTHER MONTHS A RATE OF 1 71 CENTS/KWH IS USED	NO	NO	4 26 CENTS/KWH	BI-DIRECTIONAL ENERGY METERING	UTILITY
ONTARIO HYDRO	YES	2 3 PARTY YES NO	(REFER TO APPENDIX A)	85% OF THE AVERAGE COST OF POWER FOR HIGH CAPACITY FACTORS 65% OF THE AVERAGE COST OF POWER FOR LOW CAPACITY FACTORS	YES 3 6 CENTS/KWH (REFER TO APPENDIX B)	OPTIONAL WITH A RESTRICTION OF 250KW CAPACITY (REFER TO APPENDIX B)	YES. STANDARD ENERGY RATES FOR PURCHASE DEPEND ON THE CAPACITY FACTOR FOR THE MONTH OF DELIVERY (REFER TO APPENDIX B)	5 66 CENTS/KWH	SINGLE POINT OF INTERCONNECTION HYDRO WILL INSTALL, OWN AND MAINTAIN, BILLING AND PURCHASE METERING EQUIPMENT. MORE THAN 1 POINT OF INTERCONNECTION THE GENERATOR PAYS	UTILITY
MANITOBA HYDRO	YES	2 3 PARTY NO NO	N/A	RESIDENTIAL END RATE FOR GENERATORS UP TO 20KW (3 836 CENTS/KWH) OR GENERAL SERVICE RATE UP TO 20KW (4.336 CENTS/KWH)	NO	NO	NO	3 836 CENTS/KWH	UP TO 20KW BI-DIRECTIONAL OPERATION OF EXISTING KWH METER. GREATER THAN 20KW A SEPARATE METER IN SERIES WITH EXISTING METER TO CALCULATE NET SALE/PURCHASE FROM GENERATOR	PRIVATE GENERATOR PAYS

UTILITY POLICIES ON PRIVATE GENERATION 1987/88 Chart 1 (PAGE 2)

UTILITY	RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED RATE	PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
SASKATCHEWAN POWER CORP.	YES	2 3 PARTY NO NO (DEALT WITH ON A CASE BY CASE BASIS)	(DEALT WITH ON A CASE BY CASE BASIS)	BASED UPON COSTS OF FUTURE GENERATION, AVERAGE COST OF POWER FOR SMALLER GENERATORS, PROXY PLANT METHOD FOR LARGER (>10,000KW) GENERATORS	YES APPLICABLE TO CONTRACTS IN THE 1 TO 100KW RANGE	YES APPLICABLE TO CONTRACTS IN THE 10,001 TO 50,000KW RANGE	YES APPLICABLE TO CONTRACTS IN THE 101 TO 10,000KW RANGE	6.56 CENTS/KWH	IN ACCORDANCE WITH DEPT OF CONSUMER & CORPORATE AFFAIRS REGULATIONS	PRIVATE GENERATOR INITIALLY PAYS. COST IS THEN RECOVERED FROM SASK POWER OVER DURATION OF CONTRACT.
TRANS ALTA UTILITIES CORP	YES	2 3 PARTY NO NO	N/A	AVOIDED COST (FOR 125MW RENEWABLES)	NO	NO	5.2 CENTS/KWH	5.25 CENTS/KWH	DUAL DETENTED METERING	SMALL POWER PRODUCERS PAY ALL COSTS THAT EXCEED THOSE OF A NON OPERATING INTERCONNECTION. THIS INCLUDES COSTS OF SPECIAL METERING.
ALBERTA POWER LTD.	YES	2 3 PARTY NO NO	N/A	AVOIDED COST (FOR 125MW RENEWABLES)	NO	NO	5.2 CENTS/KWH	6.26 CENTS/KWH	2 METERS 1 BUY 1 SELL	DEPENDS ON THE CONTRACT. SPECIAL METERING FOR UTILITY RESEARCH PURPOSES WOULD BE PAID FOR BY THE UTILITY
BRITISH COLUMBIA HYDRO AND POWER AUTHORITY	YES (CONNECTION OF NEW PROJECTS SUSPENDED DUE TO CURRENT SURPLUS)	2 3 PARTY NO NO	N/A	PREVIOUSLY USED TRAILING STEP OF APPLICABLE SELLING RATE, CURRENTLY MOVING TOWARD A RATE BASED ON MARGINAL VALUE	PURCHASE RATES AND STRUCTURE TO BE ESTABLISHED IN 1988			4.47 CENTS/KWH	2 METERS 1 BUY 1 SELL	UTILITY PAYS

UTILITY POLICIES ON PRIVATE GENERATION 1985

Chart 2

UTILITY	RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED RATE	PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
NEWFOUNDLAND POWER & LIGHT	YES AT PRESENT BUY FROM NFLD AND LABRADOR HYDRO AND FROM 1 WINDMILL	2 3 PARTY NO NO	PURCHASE PRICE WILL BE RELEASED TO AVOIDED COST OF ENERGY FOR THE COMPANY	IN FUTURE THE PURCHASE PRICE WILL BE TIED TO PRICE PAID TO NFLD HYDRO FOR FIRM POWER	NO	DEPENDENT ON SIZE AND TYPE OF INSTALLATION	IN FUTURE IT WILL BE TIED TO PURCHASE PRICE FROM NFLD HYDRO (2.833 CENTS/KWH) PLUS FUEL ADJUSTMENT CLAUSE	4.72 CENTS/KWH PLUS FUEL ADJUSTMENT CLAUSE	2 METERS 1 BUY 1 SELL	GENERATOR WILL PAY ALL COSTS ABOVE NORMAL INSTALLATION
NOVA SCOTIA POWER	YES	2 3 PARTY NO NO	N/A	<100KW RESIDENTIAL END RATE 100KW-15MW 70% OF MARGINAL RATE >15MW NEGOTIATED	NO	NO	<100KW 6.27 CENTS/KWH >100KW. 70% OF HOURLY MARGINAL SET MONTHLY AT 1.9 CENTS/KW (FOR A 250KW INSTALLATION)	6.27 CENTS/KWH	2 METERS 1 BUY 1 SELL	UTILITY PAYS FOR 1 METER AND INSTALLATION AND READING; CUSTOMER PAYS FOR WHAT IS NOT USUALLY NEEDED
NEW BRUNSWICK ELECTRIC POWER COMMISSION	YES	2 3 PARTY NO NO	N/A	A) DEDICATED SUPPLY (CUSTOMER HAS NO LOAD AND DELIVERS TOTAL NET PRODUCTION TO N.B. POWER) 70% OF THE VALUE OF GENERATION REPLACED B) SURPLUS ENERGY SUPPLY - 85% OF DEDICATED RATE OR 59% OF THE VALUE OF GENERATION REPLACED	NO	NO	AVG. 3-3.5 CENTS/KWH AS A FUNCTION OF VALUE OF GENERATION REPLACED	4.27 CENTS/KWH	2 METERS 1 BUY 1 SELL	CUSTOMER PAYS FOR WHAT IS NOT USUALLY REQUIRED
HYDRO QUEBEC	NO AT PRESENT UNDER REVIEW	N/A	N/A	N/A	N/A	N/A	N/A	3.71 CENTS/KWH	N/A	N/A

UTILITY POLICIES ON PRIVATE GENERATION 1985

Chart 2

(PAGE 2)

UTILITY	RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED RATE	PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
ONTARIO HYDRO	YES	2 3 PARTY NO NO	BASED ON INCREMENTAL DISTRIBUTION SYSTEM COSTS	85% OF THE WHOLESALE PRICE OF POWER	YES	YES	A) >65% CAPACITY FACTOR = 3.3 CENTS/KWH B) <65% CAPACITY FACTOR = 2.3 CENTS/KWH	4.00 CENTS/KWH	IF <100KW AND ON BLENDED RATE UNIDIRECTIONAL KWH METER IS INSTALLED IF >100KW UNIDIRECTIONAL DEMAND/ENERGY METERING INSTALLED	UTILITY PAYS
MANITOBA HYDRO	YES	2 3 PARTY NO NO	N/A	ENERGY PRODUCED IS CREDITED AGAINST ENERGY CONSUMED BY CUSTOMER	NO	NO	A) <20KW 3.175 CENTS/KWH IF RESIDENTIAL (AS IN 2 RURAL FARM INSTALLATIONS) GENERAL SERVICE CUSTOMER PAID 3.64 CENTS/KWH (<50KVA). POWER CUSTOMER (>50KVA) PAID 1.407 CENTS/KWH B) >20KW NEGOTIATED	3.175 CENTS/KWH	A) <20KW BI-DIRECTIONAL KWH METER -- TURNS BACKWARD B) >20KW IN & OUT METERS	HYDRO PROVIDES 1 METER CUSTOMER PROVIDES REST
SASKATCHEWAN POWER CORP	YES	2 3 PARTY NO NO	N/A	ENERGY PRODUCED IS CREDITED AGAINST ENERGY CONSUMED BY CUSTOMER	N/A	N/A	NO RATE AVAILABLE AS CUSTOMER CREDITED ON BILLING	4.42 CENTS/KWH	BIDIRECTIONAL METER - ENERGY FLOWS BOTH WAYS: KWH METER REGISTER PRODUCTION DEMAND METER	UTILITY SUPPLIES INSTALLS AND READS METERS. CUSTOMER PROVIDES SOCKET INSTRUMENT AND METER ENCLOSURE
TRANS ALTA UTILITIES	YES	2 3 PARTY NO NO	N/A	INSTALLATIONS<100KWH ENERGY CONSUMED BY CUSTOMER IS CREDITED AGAINST ENERGY PRODUCED ADDITIONAL ENERGY IS PAID FOR ON THE BASIS OF AVOIDED COSTS	NO	NO UNDER REVIEW	1.6 CENTS/KWH	4.4 CENTS/KWH FARM ENERGY RATE	EXPERIMENTAL METERS TAKING TIME OF DAY READING 2 METERS. 1 BUY, 1 SELL USED FOR CALCULATION OF REVENUE	EXPERIMENTAL METER PAID FOR BY THE UTILITY, PARALLEL GENERATOR PAYS FOR OTHER METERS
ALBERTA POWER LTD.	YES	2 3 PARTY NO NO	N/A	BASED ON CUSTOMERS INCREMENTAL COST OF GENERATION BUT SHALL NOT EXCEED THE COST OF EQUIVALENT CAPACITY AND ENERGY FROM COMPANY'S SYSTEM	NO	NO	NO RATE AVAILABLE. AT PRESENT NO SMALL POWER PRODUCERS ARE INTERCONNECTED	6.00 CENTS/KWH	2 METERS 1 BUY 1 SELL	DEPENDS ON THE CONTRACT. SPECIAL METERING FOR UTILITY RESEARCH PURPOSES WOULD BE PAID BY UTILITY
B.C. HYDRO	SUSPENDED DUE TO SURPLUS	2 3 PARTY NO NO	N/A	BASED ON TRAILING RATE FOR CLASS OF SERVICE, VARIES ACCORDING TO VOLTAGE LEVEL	NO	NO	ABOUT 2 CENTS/KWH OR HIGHER	4.5 CENTS/KWH	2 METERS 1 BUY 1 SELL	UTILITY PROVIDES METER, GENERATOR PAYS ALL COSTS ON GENERATOR SIDE OF METERING

EXPLANATION OF HEADINGS (Charts 1 and 2)

UTILITY POLICIES ON PRIVATE GENERATION

Parallel Generation	Electricity generation not owned or controlled by a utility, but connected to the utility power system.
Jurisdiction	The utility.
Right to Connect	The utility allows a private generator to connect.
Right to Wheel	Use of utility lines to move power. Three party wheeling is sale of power between a private generator and a private power user. Power is delivered over the electrical transmission system of the utility. Two party wheeling is similar but the generator and the user of the power are owned by the same party. The utility lines are used to move the power.
Charges	For wheeling (only applies in Ontario, 0.7 per kWh for short distance).
How is rate calculated	This is calculation of rate paid for purchased power.
Blended Rate	A capacity credit is included in price paid for energy.
Payment for Capacity	Payment for kW's as well as kWh's.
Rate Paid for Energy	Purchase rate.
Residential End Rate	Last block (least expensive) power sold to residential customers by utility.
Metering Requirements	Utility policy for metering private generation selling into the system.
Who Pays for Metering	Utility/Private generator: who pays the costs?

Appendix A

Wheeling in Ontario

1. WHEELING

Unless there are serious physical impediments (e.g. lack of distribution or transmission capability), on request, Ontario Hydro will wheel capacity power of 25 kW or more for a parallel generator to another service in Ontario owned by the parallel generator.

Where the remote service is located within a municipal utility boundary, Ontario Hydro will wheel to the boundary, provided the utility is prepared to participate in such an arrangement and wheel the power from its boundary to the service location.

When wheeling to more than one remote service, the power will be wheeled first to the location nearest to the generation site, and any remainder wheeled to the next nearest location, etc.

Arrangements for wheeling power in excess of 5,000 kW over the Bulk Electricity System will be negotiated on an individual basis.

Wheeling and wheeling administration charges are shown below and are subject to adjustment from time to time.

Wheeling Charges

Retail Distribution System (less than 50 kilovolts)

up to 20 kilometers	0.035 per kW per kM
over 20 kilometers up to 40 kilometers	0.7 per kWh
over 40 kilometers	1.41 per kWh

Bulk Electricity System

Less than 5,000 kilowatts	no charge
5,000 kilowatts or greater	3.49 per MWh or 23.04 per kW per yr.

Appendix A
(Cont'd./.. Page 2)

Wheeling Administration Charges
Within the Same Ontario Hydro Rural Area

For non-demand metered services	$10.00 per month
For demand metered services	$15.00 per month
For services with time of use recorders	$25.00 per month

Inter-Area or Area/Utility Wheeling

Add $10.00 per month to the above figures.

Effective date: January 1, 1987

Appendix B

Rates for Private Power in Ontario

2. PURCHASE ARRANGEMENTS

Standard Energy Rates

Ontario Hydro will purchase the net power delivered on a year round basis after the internal load requirements at the generating site are met (hereafter referred to as capacity power). The standard energy rates for purchase depend on the capacity factor for the month of delivery. Monthly capacity factor is determined by dividing the total kilowatt-hours delivered in a month by the product of the maximum kilowatts delivered and the number of hours in the month.

Optional Time-Differentiated Rates

Optional time-differentiated rates are available for parallel generators capable of delivering 250 kilowatts or more of capacity power. This rate structure has both capacity (kW) and energy components and is beneficial for generation in excess of 65 per cent capacity factor delivered mainly during Ontario Hydro's peak periods, when it is of greater value to the power system.

Rates for Occasional Deliveries from Large Direct Customers (over 5,000 kW)

Reduced rates are applicable to the purchase of internally generated electrical energy surplus to the needs of Ontario Hydro's Direct Customers delivered to the Bulk Electricity System (50 kilovolts or greater) on an occasional basis only (as and when available).

Large Generators

To provide management control of capacity on the Bulk Electricity System, purchases from large capacity generators (as determined by Ontario Hydro) may require negotiation of special conditions and will be handled on an individual basis.

Purchase rates are shown in Table I and are subject to annual adjustment.

Contracts for the purchase of capacity power will have an initial term of twenty years and will be renewable on a yearly basis thereafter.

Table I

Rates for Purchase of Parallel Generation in Ontario

Standard Energy Rates 1987

For capacity factors of 65% or greater	- 3.60 cents per kWh
For capacity factors below 65%	- 2.54 cents per kWh

Based on the rated kilowatt capacity of the generator or the peak measured kilowatts delivered in the month.

Fixed Ten-Year Energy Rate

For capacity factors of 65% or greater	- 4.94 cents per kWh.

Optional Rates - for generators with capacities of 250 kW or greater

Capacity Rates

Winter	$7.62 per kW* per month
Summer	$3.81 per kW* per month

* as measured during the peak period of the month. No capacity payment will be made in any month that the capacity factor is below 65%.

Appendix B
Table I
(Cont'd./.. Page 4)

Energy Rates

Winter peak	3.05 cents per kWh
Winter off-peak	2.45 cents per kWh
Summer peak	2.67 cents per kWh
Summer off-peak	1.67 cents per kWh

Time of Use

Winter - October through March
Summer - April through September
Peak - 7 am to 11 pm weekdays
Off-peak - 11 pm to 7 am weekdays plus all weekends and public holidays

Rate for Purchase from Direct Customers (over 5,000 kW) Delivering Energy to the Bulk electricity system on an Occasional Basis Only

3.60 cents per kWh multiplied by the capacity factor based on the peak delivery for the month, with a floor price equal to the energy rate applicable to Direct customer purchases from Ontario Hydro. In 1987, the floor price is 2.13 cents per kWh.

Effective date: January 1, 1987

Modelling of Energy Limited Units in Generating Capacity Reliability Evaluation of Small Hydro Systems

By

R. Billinton, J. Oteng-Adjei

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MODELING OF ENERGY LIMITED UNITS IN GENERATING CAPACITY RELIABILITY EVALUATION OF SMALL HYDRO SYSTEMS

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ABSTRACT

A generating system may fail to supply the load demand due to a shortage of capacity associated with equipment outages or due to a shortage of basic energy resources or both. Traditional models usually ignore the effects of energy shortages on the basis that sufficient energy resources will be held in reserve for use in critical periods. The assumption of abundant energy may not, however, be valid especially for small hydro systems. It is therefore essential that in these cases, any energy limitation problems associated with the generating units be included in conventional studies. This paper investigates the effects of energy limitations of generating units on overall system reliability. The load modification method is used in this paper to evaluate the impact of energy limited units on the system reliability indices and the system production cost.

1. INTRODUCTION

Electric power systems play a central role in a modern society by providing the most essential means for large-scale conversion, transportation and distribution of electrical energy. The primary function of an electric power system is to satisfy the system load requirements as economically as possible and with a reasonable assurance of continuity and quality of electricity supply. The ability of the power system to meet its load requirements at any point in time is referred to as the "reliability" of the system [1]. Generating capacity reliability evaluation is basically concerned with assessing the amount of generating capacity that must be installed in order to satisfy the system load at an acceptable risk level [2]. A lot of work has been done in the area of generating system adequacy assessment [3]. Most generating capacity reliability studies assume that, there are no inherent energy limitations associated with generating units [1,4,5] and proceed to consider only the effects of unit forced outages and uncertain load requirements. The perception that there is an abundance of energy is gradually disappearing and it is slowly being realized that shortages in primary energy supply must be included in conventional adequacy studies.

Many developing countries have waterfalls and medium size rivers located in the rural areas which can be used to create local generating facilities. These stations may stand alone or be connected by appropriate transmission facilities if it is economically viable. Reliability evaluation of generating facilities composed of small hydro units is complicated by the fact that in addition to possible equipment failure, there is also the possibility of inherent insufficient energy due to water shortages. Recognition of these limitations and their impact on system planning cannot be evaluated using conventional deterministic generating capacity planning criteria. This paper describes a methodology known as load modification which has the capability to model generating units including those which are energy limited [6,7]. A series of studies have also been performed to examine the effects of energy limited units in generating capacity adequacy assessment.

2. THE LOAD MODIFICATION TECHNIQUE

The load modification technique is an analytical method. It is a process of modifying a given load model with a generation capacity distribution to give an equivalent load model. The equivalent load model idea was first initiated by Baleriaux et al [8]. The method presented in this paper was developed at the University of Saskatchewan [6,9].

The concept behind the load modification method lies in answering the question, "How does the load appear to the remainder of the system capacity when a given generating unit is loaded to supply energy to the system?" The solution to this question can be deemed as a process of modifying the load duration curve with a given generating capacity distribution to produce an equivalent load duration curve. Repeated application of this approach for each generating unit in the system results in a final unsupplied load curve. A prerequisite for this method is the knowledge of the merit loading order of the generating units. The indices generated by this technique are Loss of Load Expectation (LOLE), Loss of Energy Expectation (LOEE), Expected Energy Supplied (EES) by each unit and the production cost for the units and system. The LOLE index measures the average number of days or hours in a year that insufficient generating capacity is available to serve the daily or hourly peak load. This index is the most widely used probabilistic index in generation planning studies. The LOEE index specifies the expected energy that will not be supplied by the generation system due to those occasions when the load demand exceeds the available generating capacity. The load modification method can be used effectively to simultaneously evaluated reliability indices and production costs in both isolated and interconnected systems [9].

The load modification technique can also be used to model generating units taking into account the limitations on the energy available to them. Conceptually, the load modification process modifies the original load model using the capacity distribution of an energy limited unit to obtain a capacity modified load curve. The area enclosed by the original and the capacity modified load curve would have been the expected energy supplied by this unit with reference to its position on the priority loading list if it had not been energy limited. The second stage of the modification process considers the energy distribution of the unit. The energy modification starts at the top of the Load Duration Curve (LDC). At each value of load, the area between the original LDC and the capacity modified curve above the load value is calculated. This area represents the energy output of the energy limited unit if it is operated at the time when system load equals or exceeds the value of load under consideration. If the unit has that much, or more, energy available to it, the value of the duration at the load point being considered to that on the capacity modified curve. If not, then the value for the duration will correspond to the duration on the original LDC. The probabilities associated with each of these two events are taken from the cumulative energy distribution for the unit and used to weight the two values of load duration. The final energy modified LDC is determined by Equation 1 [6,9].

$$D_f(L) = d_c(L) \,.\, P[E(L)] + d_o(L) \,.\, [1 - P[E(L)]] \qquad (1)$$

where:

$D_f(L)$ = duration of load level L on the final curve,

d_c = duration of load level L on the capacity modified curve,

d_o = duration of load level L on the original load curve,

E(L) = the area between the capacity modified curve and original load curve and above the load level L, and

P[E(L)] = probability of energy equalling or exceeding E(L) MWh.

In summary, the first step is to capacity modify the load duration curve using a conditional probability approach. The modified curve is the equivalent load curve for the rest of the units in the system if the unit used for modification was first on the priority list. The capacity-modified curve is then energy-modified using the energy probability distribution of the unit under consideration. The final modified curve is then used in the normal manner with the rest of the generating units in the system to determine their expected energy output and the resulting expected energy not supplied.

3. ILLUSTRATIVE EXAMPLE

The concepts of the load modification technique described above are illustrated using a small test system made up of three generating units. Table 1 gives the generation model for unit #1. This unit can reside in three states. The example therefore illustrates how derated state representations can be included in the analysis. Unit #2 has a capacity of 30.00 MW and a forced outage rate of 0.03 and unit #3 has a capacity of 20.00 MW with a forced outage rate of 0.04.

Table 1. Generation model for Unit #1

Capacity in (MW)	Individual Probability
0.00	0.05
15.00	0.30
25.00	0.65
	1.00

CASE 1: Capacity Modification

The generating units are assumed to be loaded to supply energy to the system in the order of increasing average operating cost as shown in Table 2. The load model for this test system is represented by a load duration curve for a period of 100 hours. The actual LDC may not be a simple straight line as given in Figure 1 but it can be represented by a series of segments.

Table 2. Merit Loading Order of the Units.

Loading order	Unit identity	Rated capacity (MW)	Average operating cost ($/MWh)
1	#1	25.00	1.00
2	#2	30.00	2.00
3	#3	20.00	3.00

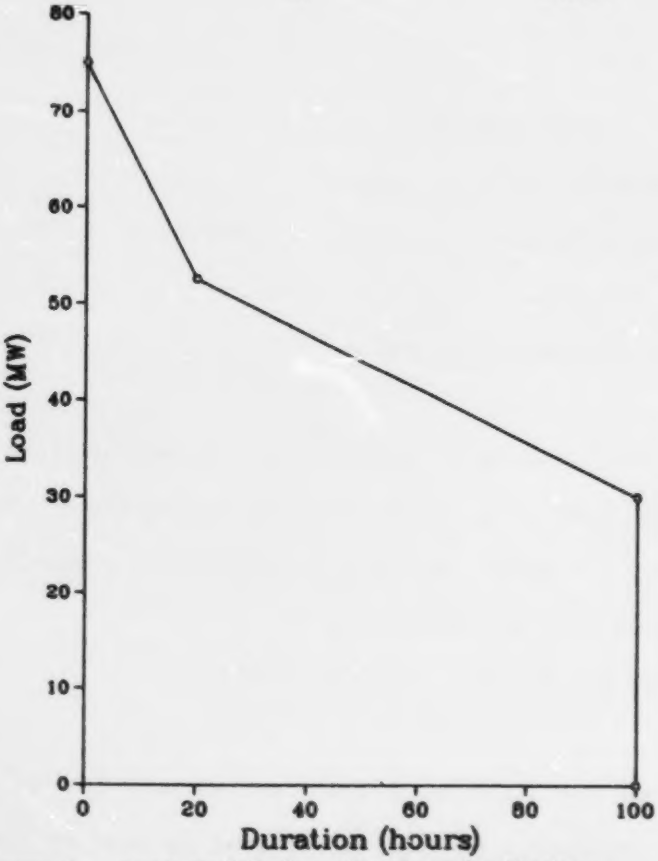

Figure 1. Load Model for the Example System.

The load modification process is initiated by considering unit #1 which is at the top of the loading priority list. When this unit is loaded to supply energy to the system, the LDC as seen by the remaining units can exist at three different positions depending on the operating capacity of unit #1. If the unit is operating at rated capacity, the LDC as seen by the rest of the system is 25.00 MW lower than its original LDC. If the unit is operating at a derated capacity of 15.00 MW, the LDC is 15.00 MW lower and if the unit is down, the curve remains the same. These three situations are shown in Figure 2. The basic mathematical formula underlying the load modification method is given by Equation 2 [7,9].

$$D(L) = \sum_{i=1}^{N} d_i(L)\, P_i \tag{2}$$

where:

$D(L)$ = expected duration of load level L,

C_i = capacity of i^{th} capacity state of unit,

$d_i(L)$ = duration of load level L on the original LDC reduced by C_i MW,

P_i = probability of C_i MW, and

N = number of capacity states of the unit.

The application of Equation 2 can be illustrated by a simple example. The duration of the 37.5 MW load level is a random variable having three possible values. It has a value of 11.111 hours, 20 hours or 73.333 hours depending on the operating capacity level of unit #1. From Equation 2,

$$D(37.5) = 11.111 \times 0.65 + 20.0 \times 0.30 + 73.333 \times 0.05$$
$$= 16.889 \text{ hours}$$

If the calculations described by Equation 2 are carried out for all load levels, the resulting curve represents the equivalent load as seen by the rest of the units in the system. The equivalent load curve is the "capacity-modified" curve shown in Figure 2. It must be noted that, in the modification process only those load levels where an intersection of the line segments occurs in one of the three load duration curves used in the calculation are considered. By treating the capacity modified curve of Figure 2 as the original LDC and modifying it using the two capacity states of unit #2 which is second on the priority loading list, curve #2 of Figure 3 is obtained. Similarly, unit #3 which is the last unit on the loading list can be used to modify curve #2 to yield curve #3 of Figure 3. Curve #3 is the final LDC of the test system. The LOLE index of the system can be determined from the final LDC by examining the duration of the 0.00 MW load level. This index happens to be 6.862 hours in a period of 100 hours. The area under curve #3 is the expected load energy not supplied by the generation system and its value is 64.069 MWh.

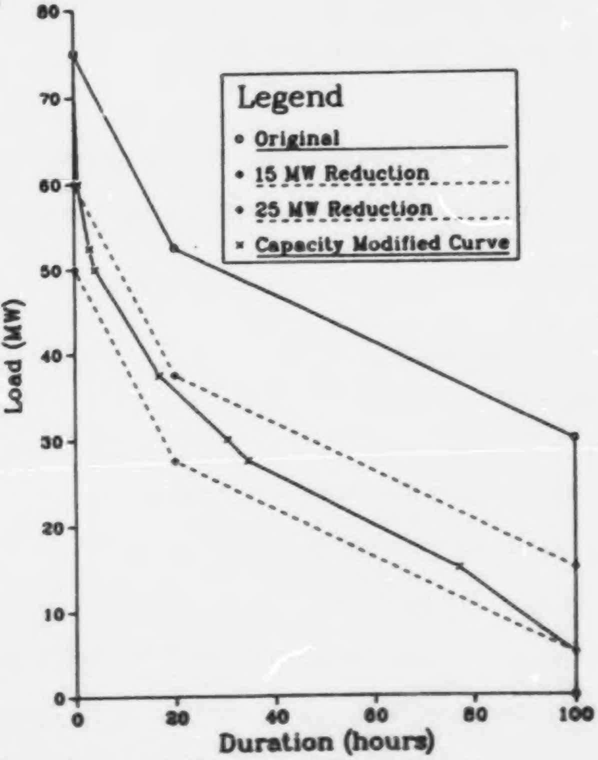

Figure 2. Capacity Modification with Unit #1.

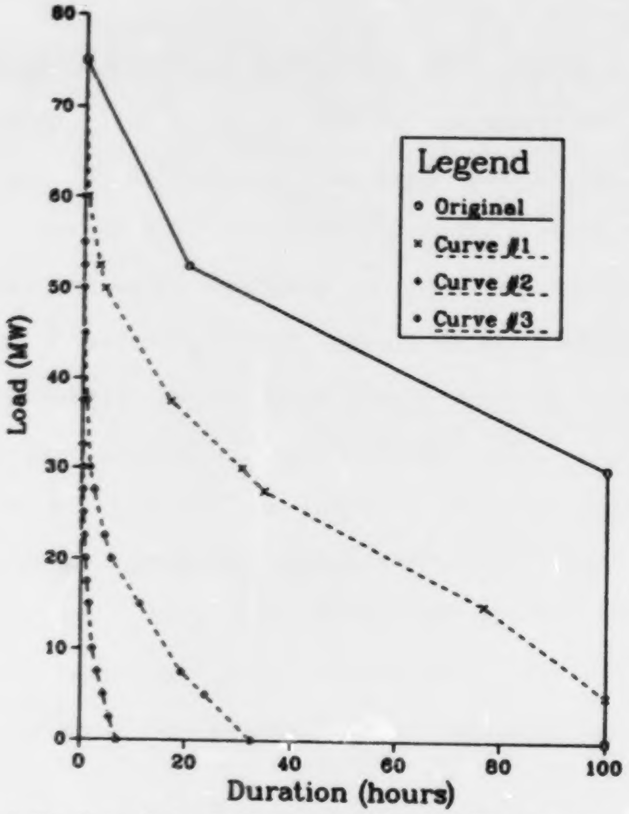

Figure 3. Original and Equivalent Load Duration Curves.

The total production cost of the system can be evaluated by summing the energy outputs of each unit in the system multiplied by their corresponding average operating cost. Thus,

$$\text{Total Production Cost} = \sum_{k}^{M} (EES_k)(AOC_k) \tag{3}$$

where:

M = total number of generating units in the system,

EES_k = expected energy supplied by unit #k, and

AOC_k = average operating cost of unit #k.

The EES by unit #k is equal to the area enclosed by the equivalent load duration curves before and after the unit is loaded to the system. Table 3 shows the production cost analysis.

Table 3. Production Cost of Example System.

Loading order	Unit identity	Rated capacity (MW)	EES (MWh)	Operating cost ($/MWh)	Production cost ($)
1	#1	25.00	2075.00	1.00	2075.00
2	#2	30.00	2098.00	2.00	4196.60
3	#3	20.00	337.63	3.00	1012.89
			4510.63		7284.49

CASE 2: Energy Modification

The simplest energy limitation situation to incorporate into the analysis is the condition in which the output capacity of a unit is dictated by the energy available. An example of this energy limitation is a run-of-the river hydro installation with little or no storage. The flow rate determines the unit capacity output. The unit is then represented as a multi-state unit in which the capacity states correspond to the water flow rates. The analysis in the Case 1 study was carried out without considering any inherent energy limitations associated with unit #3. In order to illustrate the capability of the load modification technique to include energy limitation aspects of generating units, unit #3 is assumed to be energy limited with an energy distribution given in Table 4. The energy distribution assumes there is only one possible value of stored energy for the period being considered with the probability of occurrence being one. More energy states can be added for a more exact model if additional data are available on the energy distribution. The new loading positions are given in Table 5.

Table 4. Energy Distribution of Unit #3.

Energy available (MWh)	Cumulative probability
1200.00	1.00

Table 5. Priority Loading Order of the Units.

Loading order	Unit identity	Rated capacity (MW)	Average operating cost ($/MWh)
1	#3	20.00	0.50
2	#1	25.00	1.00
3	#2	30.00	2.00

The original LDC is first of all capacity modified using unit #3 at priority loading position one to yield the capacity modified curve of Figure 4. By making use of Equation 1 and the energy distribution shown in Table 4, the effect of energy limitation of unit #3 can be incorporated in the analysis to yield the energy modified curve given in Figure 4. Consider the 32.50 MW load point. The area between the original and capacity modified load curves above this load of 32.50 MW is 1067.069 MWh. From Table 5, the probability of unit #3 having 1067.079 MWh of energy or more is 1.0. Using Equation 1,

$$D(32.5) = 22.844 \times 1.0 + 91.111\ [1.0 - 1.0]$$

$$= 22.844 \text{ hours}$$

The energy modified curve is then used in the normal manner with the rest of the units of the system to determine their reliability indices and production costs.

4. SENSITIVITY STUDIES

Sensitivity analysis can be used to evaluate the impact of perturbing the data on the performance measures of a system. A series of studies have been performed using the Expected Energy Not Supplied (EENS) as the system adequacy index and the load modification method to examine the impact of energy limited units on generating capacity reliability studies. The maximum energy available to a generating unit is always taken to be the product of its rated capacity

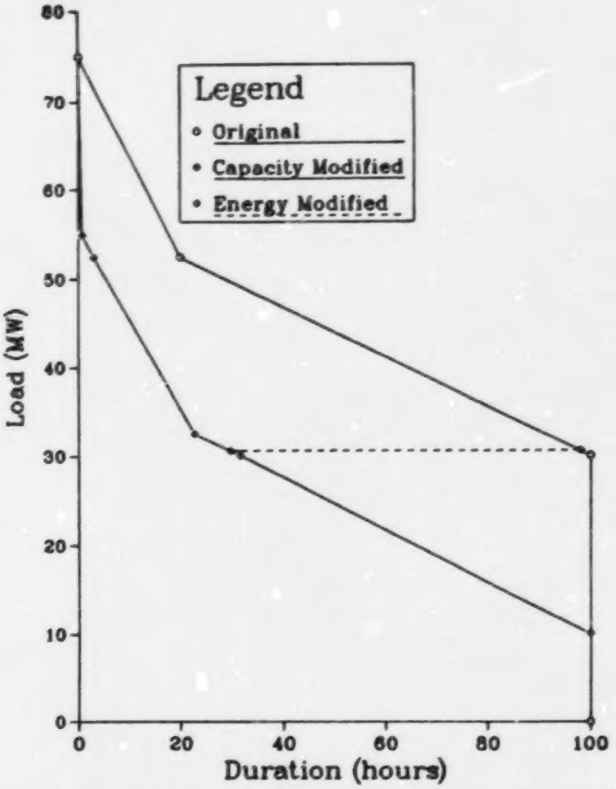

Figure 4. Capacity and Energy Modification Using Unit #3.

and the period of study. The rest of the paper presents the results of a series of studies performed to investigate the impact of unit energy limitations on the overall system adequacy.

The Impact of Unit Energy Limitations on System EENS

Unit #3 is deemed to be energy limited with varying energy distributions similar to that shown in Table 4. The effect of this energy limitation on system EENS was examined at a fixed unit Forced Outage Rate (FOR). The results are shown in Figure 5. They reveal that the system EENS increases as the energy available to unit #3 decreases. The relationship is, however, not linear. Figure 5 also reveals that the system EENS increases with higher FOR values of the energy limited unit.

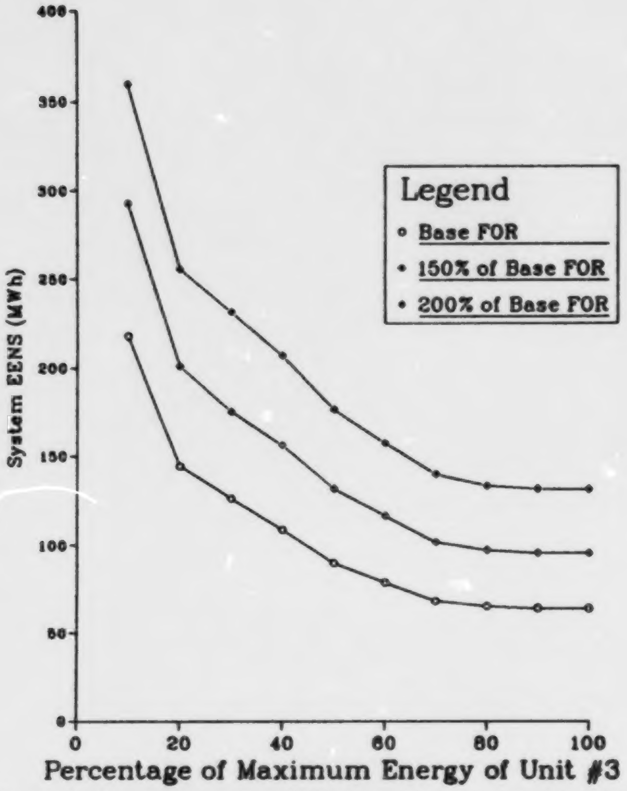

Figure 5. Variation of System EENS with the Energy Available to Unit #3.

The Impact of Loading Positions of the Energy Limited Unit on System EENS

The loading procedure is the order in which the various units are assigned to generation in order to meet the instantaneous demand for power while minimizing production cost. Conventional practice is to load the units for generation in order of their average operating costs. When there are no energy limited units in the system, the loading order only affects the system production cost and not the system reliability indices. This idea is shown in Figure 6. Consider unit #3 to be energy limited. The system EENS variations with the energy available to unit #3 were obtained while placing unit #3 at different positions on the loading order. Figure 7 shows that loading unit #3 at position three results in a much smaller system EENS. This may be attributed to the fact that, at position three, unit #3 behaves as if it is non-energy limited since the energy available to it most of the time is greater than the energy demand. This result is, however, at the expense of higher total production cost as shown in Figure 7. The conclusion is that, some form of trade-off is required between the system production cost and system EENS in deciding on the loading position of energy limited units.

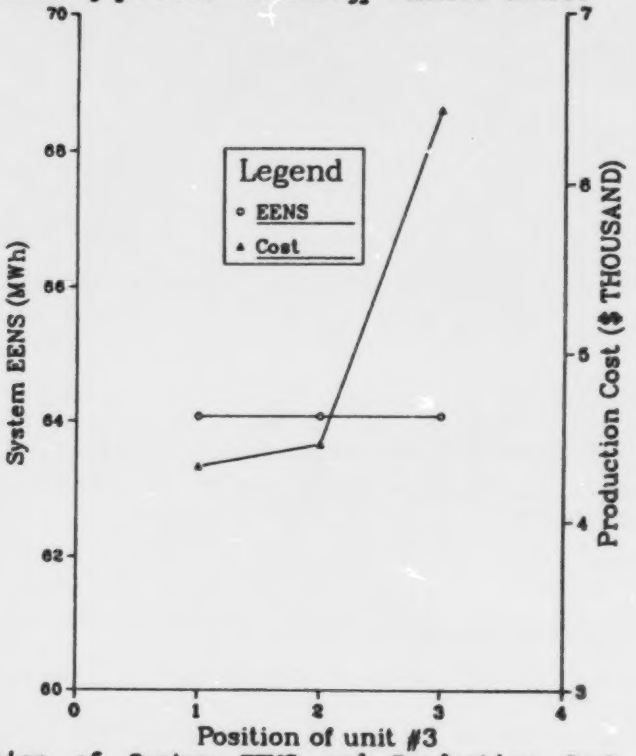

Figure 6. Variation of System EENS and Production Cost with the Loading Position of Unit #3.

The Impact on System EENS of Considering the Energy Limited Units as Joint or Separated Generation Sources

Conventional adequacy assessment methods combine all units of the system into a single capacity outage probability table which is then convolved with the load model to yield the risk indices. The load modification technique has the ability to accept the total system capacity outage probability table or the

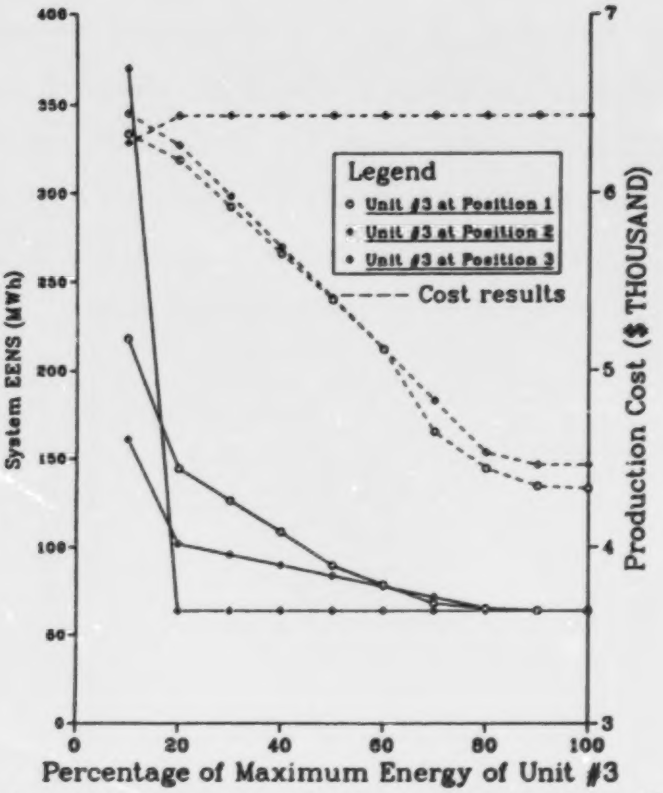

Figure 7. Effects of the Loading Positions of Unit #3 on the System EENS and Production Cost.

individual unit capacity outage probability table in the evaluation of system reliability indices. If the units of the system or a particular subsystem are combined to give a simple or subsystem capacity outage probability table, the application is referred to as a JOINT case. If the capacity outage probability tables of the individual units are used, then the application is referred to as a SEPARATED case. The system reliability indices are constant for both joint and separated cases if all the units in the system are non-energy limited.

Consider units #2 and #3 to be energy limited. These two units are combined to give the single capacity outage probability table shown in Table 6. The rated capacity of the combined unit is 50.00 MW and the maximum energy required is 5000.0 MWh for a study period of 100 hours. The amount of energy available to this new multi-state unit was varied and the corresponding system EENS obtained. The system EENS as a function of the available energy was also obtained by considering each unit as a separate generation source. The results for this study are shown in Figure 8. They indicate that if the energy available to these units is between 50% and 90% of the maximum energy required, the joint case gives a lower system EENS. This observation is enhanced in Figure 9 which depicts the situation when all the units in the system are assumed to be energy limited. It can be concluded from this study that, where energy limitation exists, hydro units at the same plant should be incorporated into a joint model in generating capacity adequacy assessment. If the units are at different stations, and possibly subjected to different energy constraints, then the separated model should be adopted in the analysis.

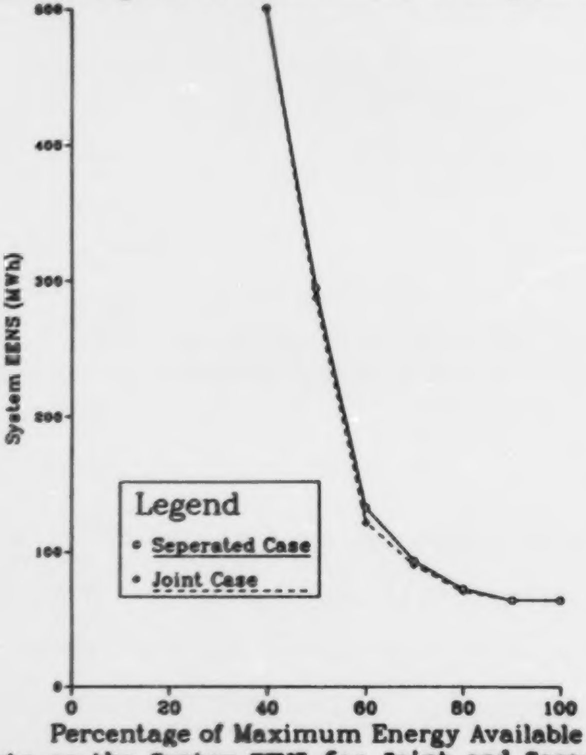

Figure 8. Effects on the System EENS for Joint and Separated Models.

Table 6. Combined Capacity Outage Probability Table for units #2 and #3.

Capacity in (MW)	Individual probability
0.00	0.9312
20.00	0.0388
30.00	0.0288
50.00	0.0012
	1.0000

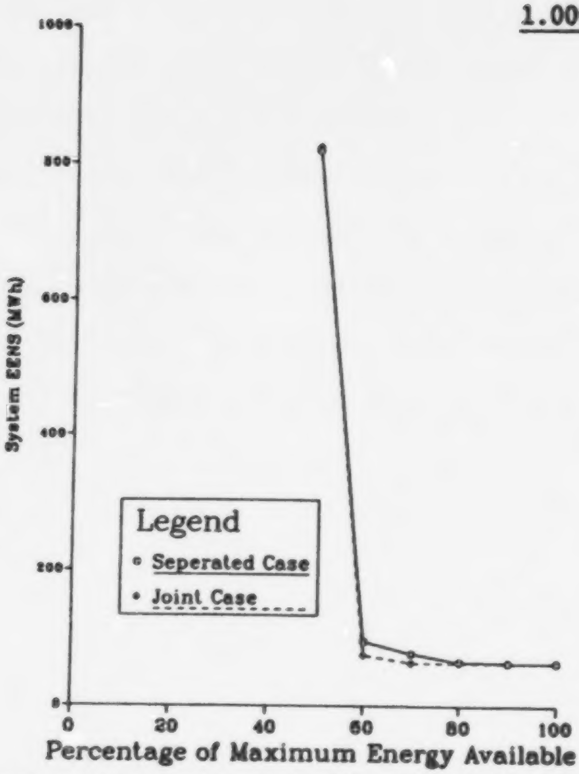

Figure 9. Effects on the System EENS When All Units are Energy Limited.

5. CONCLUSION

Energy limitations in generating capacity studies are normally associated with hydraulic facilities. This may not be the case in future and the limitations can easily arise with gas or oil fixed units. This paper has illustrated the basic concepts of the load modification technique by application to a simple test system. The results for a series of sensitivity studies performed to examine the effects of energy limited units on generating capacity reliability evaluation are also presented in this paper. These studies show that the inherent energy limitations associated with small hydro units can be an essential factor which should be incorporated in generating capacity adequacy assessment. The load modification approach has been illustrated by application to a simple example which could be considered as a small system or a single isolated hydro plant. The technique can be used in systems of any size but can be easily applied without any great computational effort to small hydro facilities. The approach retains the basic load duration curve throughout the analysis in the form familiar to most power system analysts and therefore provides a practical quantitative appreciation of the system reliability.

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The Economics and Social Impact of Small Scale Hydropower

By
K. Goldsmith

10

THE ECONOMIC AND SOCIAL IMPACT ON SMALL-SCALE HYDROPOWER

by

K. GOLDSMITH

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THE ECONOMIC AND SOCIAL IMPACT OF SMALL-SCALE HYDROPOWER

K. Goldsmith

SYNOPSIS

Utilities responsible for the promotion and management of small-scale hydropower schemes will in most cases have their efforts taken up with the problems of supplying the bulk of their consumers in urban and already interconnected areas. Small-scale hydropower will present for them a marginal activity with only minor impact on their work and their financial operations. Nevertheless, the economic merit of every scheme must be properly justified before an investment decision can be taken. The economic appraisal methods used for small schemes are basically the same as for all new generation proposals. The methods rely essentially on a comparative analysis of alternative ways of supplying a pre-determined demand for electricity either at an isolated load centre or in support of a relatively weak distribution system. Because of the scale effect, costs are likely to be high both for the hydro scheme and for its alternative solution but the advantage of the hydro case is often only marginal and a decision in favour of its implementation may then be difficult to justify.

Remote areas, which are the principal beneficiaries of small-scale hydropower, are often under-priviliged in socio-economic terms; they are starved of energy, the quality of life of the resident population is low and the local economy is stagnant; this at least is the situation in the majority of the developing countries. If the supply of energy can be improved, living standards will be raised and local economic activity stimulated which ultimately affects the national scene as a whole. It is important therefore to take account of socio-economic impacts in the appraisal of small-scale hydro schemes, especially where the directly quantifiable economic merit is only marginal. Although largely intangible, some socio-economic impacts can be quantified in comparative terms and can then be used to support an economic evaluation. Negative impacts can also arise in cases where a scheme disturbs the amenity and livelihood of the local population and this must also be taken into account in the appraisal.

Impact analysis does not usually extend to an assessment of price-demand resilience of the potential consumers. Supplies given from small-scale sources are often expensive and unless there is cross-subsidisation with the more affluent areas of the utility in question, predicted demands may not materialise and financial targets may not be reached. The likely consumer response should therefore be considered in the socio-economic impact assessment to form an estimate of possible subsidisation needs at the outset of the project development process.

The paper reviews these matters, especially in the light of experience in the developing countries.

THE ECONOMIC AND SOCIAL IMPACT OF SMALL-SCALE HYDROPOWER

K. Goldsmith, Consultant

Summary

The paper examines the nature of socio-economic impact analysis and the part it can play in the appraisal of small-scale hydropower. Methodologies for the numerical evaluation of socio-economic features are reviewed and the future role of impact analysis is discussed.

Overview

Many small rivers are suitable for hydropower development. Some have already been exploited and others used for water supply or irrigation purposes where the addition of a hydropower component could prove attractive, but many are left entirely undeveloped. Funding problems and development inertia have probably contributed to small schemes not being as widely implemented as the scale of the exploitable resources may warrant. Development inertia arises out of recognition of obstacles - principally non-technical - which may be real or only surmised but which are likely to impede implementation of otherwise attractive project proposals. To overcome such obstacles may seem to demand a disproportionate effort. On the technical side, concentration on the development of larger schemes has tended to inhibit the emergence of a specific small-scale technology. The merits of small-scale hydropower are therefore still being debated at a time when all the elements involved might be thought to have been fully resolved. The prospects of hydropower are, of course, closely linked with those of electrification as such, but electricity demand throughout the world is still advancing more rapidly than the demand for energy as a whole.

Views differ on what station size may be defined as "small". An often quoted upper limit is of the order of 10 - 15 MW although somewhat larger capacities may still be small in relation to the massive schemes that have been built in recent times. In theory, there should be no lower limit but installations of less than about 250 kW require a different approach to planning and construction with substantial simplification and local input to keep costs in check. The first hydro stations built about 100 years ago came within the definition of "small" but further development of the hydro sector was shaped by three considerations:

1. the realisation that substantial economies could be achieved - in terms of the specific investment requirements (per kW installed) - by increasing the size of the project.
2. the ready acceptance of electricity as a most convenient and versatile energy form and the consequently rapid growth of power markets.
3. the improvements in power transmission technology which opened up wider markets to the site-restricted hydro plants.

Hydro schemes thus became progressively larger and more capital-intensive, in line with the larger power markets which they supplied. Power utilities became increasingly concerned with the problems of meeting the electricity demand of the bulk of their consumers resident in the electrified centres and found it difficult to devote much attention to schemes of small size which presented for them an activity of only minor influence on their operations. By implication, a small scheme deals with a small power market; this is almost invariably a demand in rural and outlying areas, at any rate as far as the public supply is concerned.

Distribution networks cover generally the whole national territory of the industrialised countries and leave only a few pockets in rural and island situations available for a small-scale supply, with the exception of course of autoproducers. The supply structure in the developing countries is different. Electrification in the urban and industrial centres tends to be similar to that in the industrialised world; distribution coverage is fairly dense and supplied from relatively large central power plants. Climatic, social and economic differences do however come into play and lead to considerably lower specific consumption (per capita) even at the demand centres. The outlying areas have usually been left behind and their electrification is still in its infancy, with only a very small part of the population connected to an electricity supply. These areas are also underprivileged in socio-economic terms and have in many cases not advanced beyond a subsistence economy but it is here where the primary market for small-scale power generation is found. The market will be conditioned by the economically retarded situation of its potential consumers.

The fact that only a few of the rural inhabitants in the developing countries benefit from an electricity supply at a time when, from the technological aspect, there seems to be no reason why there should not be ample supplies for everyone, indicates that there are serious obstacles to overcome. The obstacles are primarily economic and financial; they depend not so much on the purchasing power of the local population - although this is generally weak - but rather on the means central governments and utilities can devote to investment for only a marginal activity which rural electrification implies. Overcoming these obstacles would produce considerable socio-economic benefits both for the rural population and ultimately for the community as a whole, benefits which have already been largely achieved in the fully electrified world. Obstacles can also be encountered in those places in the industrialised world where small-scale hydropower can still play a role but they tend to be of a different kind; they will be primarily environmental, procedural and regulatory. Discussion of economic and social impacts will necessarily concentrate on the developing countries where the most serious economic and social problems are experienced and where more extensive electrification can bring considerable benefits for the national economy as a whole.

Economic Analysis

Small-scale hydro schemes are inherently expensive per kW installed, costing about 2 - 6 times as much as thermal power plant of the same size. A very thorough economic analysis is necessary to justify the extra investment which is often - but not always - recouped by the lower operating costs, the fuel saving and the longer asset life of the hydro facility. Analytical methods have by now become largely standardised under the influence of the investment institutions wishing to establish the credit-worthiness of a project. The methods rely mostly on a comparison of alternative ways of meeting a predetermined power demand and of the benefits and costs which the alternative solutions are expected to achieve over their lifetime. Costs are normally computed for the point of supply; this means that transmission between power plant and the power infeed points to the local distribution network is included in the costs but distribution and consumer-related expenses are not included. Tariffs or the yield expected from electricity sales do not enter into the computation of the benefits from the generation project. The benefits are the cost advantage of the hydro case over an alternative solution which may be another generation scheme, generally thermal, or an extension of an existing network to the load centre the hydro plant is to supply.

The approach adopted for economic analysis is basically the same as for any new generation proposal. An optimised design leading to a least-cost solution is developed for each alternative and the quantifiable benefits and costs are computed, normally by discounting techniques to establish a single present value for the cash streams which extend over the anticipated lifetime of the assets concerned. Opinions differ on the inclusion of price escalation in such computations, bearing in mind that any projection for a period of perhaps 50 - 60 years can be no more than guesswork. The effect of changes in future costs is best tested by sensitivity analysis.

If benefits exceed costs by an acceptable margin, the economic merit of the project is judges to be adequate and its credit-worthiness established. The interpretation of an "acceptable margin" depends largely on the nature and situation of the developer and the requirements of his financing institution. A common yardstick for measuring the adquacy of the return on the investment is the "opportunity cost of capital" in the economy in question. This is a rate determined by the return expected from any capital investment in the public or private sector, depending on whether the organisation sponsoring the development in public - governmental or quasi-governmental - or private hands. Acceptable public sector returns are generally lower to reflect the more favourable conditions under which finance can be obtained. Financing institutions sometimes ask for a higher return, say 8% instead of 5% per annum, in order to encourage the developer to build up a capital base for a greater degree of self-financing of future projects. Private developers may have to raise capital on less favourable terms and will then require a higher return. They often use the "pay-back period" as an index of profitability; this is the period over which the initial capital outlay can be recouped by the accumulated net benefits from the scheme. They will also want to be assured of their markets. If a major proportion of the output of their plants is to be sold to the public supply, they would wish to secure a firm commitment that the power available will in fact be bought.

A number of different parties can be involved in an investment decision - financing institutions, governments, utilities and other developers. They will apply their own criteria to credit-worthiness and it is therefore not advisable to lay down general profitability indices for any given hydro proposal. The index will depend on the circumstances of the developer and the attitude of the financing agency.

The output from a hydro scheme depends on the hydrology of the particular river system which it exploits. Two problems can arise which will affect the economic merit and the decision based on it:

1. With development effort concentrating on the larger hydro projects for a number of years, hydrological surveys of small rivers have often been only superficially carried out and few reliable data may be available from which the long-term production pattern of a small scheme can be derived. The fact that the power market for a small scheme will also be uncertain for the longer term only exacerbates the problem. The economic merit established in the planning phase may therefore need to be tested for different assumptions before a final decision is taken to go ahead with the project.

2. Variable run-off conditions resulting from seasonal climatic changes can give rise to periods of insufficient water flow for hydro generation at the rated level. Supplementary power will then be needed from other sources, thermal plants - usually diesel stations - or network extensions, to firm up the hydro supply. Where a hydro plant is to replace diesel generation, diesel plant may have to be retained in service to compensate for shortfalls in hydro production. A thermal or network cost component will then be superimposed on the hydro cost and it can become difficult to achieve an acceptable economic return in such circumstances. Appropriate thermal or network costs entering into the equation will be the average production costs referred to the power infeed point of the hydro scheme.

These matters can impose a considerable element of uncertainty on project proposals, particularly in the tropical and sub-tropical regions of the developing countries where large changes in seasonal rainfall occur. The extra costs of supplementary generation can greatly reduce the merit of small hydro schemes. Projects which can have a beneficial impact on the economy and society at large are then in danger of being set aside because they fail the test of economic viability on conventional methods of appraisal; their credit rating may be too low to attract the funds needed for their implementation. This makes it necessary to take account also of the wider though less readily quantifiable socio-economic benefits which a hydro scheme can bring, offset of course by the socio-economic costs which can hinder the success of a scheme. Benefits and costs should be weighed objectively to avoid abandoning a development simply because of perceived impediments.

Socio-Economic Definitions

Economic analysis can be defined as dealing with the project itself - with project economics - whereas socio-economic considerations deal with the impact of the project on the economy, the society and the environment. This impact is two-fold: it is caused in the first place by the hydro development as such and in turn by the electrification resulting from it.

For an assessment of socio-economic impacts, the following components need to be taken into account:

1. Positive impacts which bring benefits for the project.

   Negative impacts which result in impairment or costs (these might be termed "disbenefits").

2. Primary impacts which affect the immediate project area, including the load centres supplied, at a micro-economic level.

   Secondary impacts arising from the consequential effect of primary impacts on a region and on the country as a whole, or on the macro-economy.

3. Direct impacts arising from the project as such.

   Indirect impacts resulting from the electrification which the project makes possible.

Economic and social impacts can be analysed individually although they are related; economic advancement will lead to an improvement in social conditions and vice versa. A distinction must also be made between the nature of the economies affected by the proposed scheme. The impact will be different in an industrialised and a developing environment and different analytical procedures will be involved. Since small-scale hydropower will play a more important role in the economy of the developing countries, the issues arising there seem to warrant first consideration.

The issues for positive impacts are straightforward:

- On the social side, an electricity supply brings light, heat and power to a section of society that may have been previously deprived of this service, if only partially. This will enhance their quality of life and help in raising standards of health, education and welfare. It will narrow the social gap between the rural and urban population and bring greater equality to the social structure. The difficulties of quantifying such benefits have tended to overshadow their importance.
- On the economic side, the project itself can create limited and usually temporary employment opportunities and offer a market for local materials and goods for construction and operation (these are direct impacts). Electrification will stimulate the local economy, promote greater commercial and industrial activity, create better employment opportunities and offer means of advancement from a subsistence to a monetary economy (these are indirect impacts). There will be a consequential (secondary) effect on the national

economy due to the improved local output and the reduced drain on resources which a predominantly subsistence economy may have imposed. Deforestation - environmentally and economically most damaging - will be lessened or even arrested, with important consequences for soil conservation and ultimately for agricultural production which will again strengthen the economy. Economic benefits are usually easier to assess than social benefits, especially where there is a clearly identifiable demand for new industrial or commercial facilities which electrification permits to satisfy.

There is also a benefit to the infrastructure which will accrue in the first instance to the local population but ultimately to the whole country. The project will bring about improvements in communications and both its direct and indirect impacts will encourage the provision of local schools, health centres and other public services. The growth in the local economy will yield gradually rising fiscal contributions.

The scale of these benefits may not be large in absolute terms but it can be significant in areas which have been underprivileged hitherto and which had to rely largely on external support for maintaining even their subsistence level. The benefits may be less significant in an area already partially or fully electrified but they may nevertheless be large enough to influence an investment decision. Intensively developed areas are unlikely to need socio-economic support for an investment proposal; the directly quantifiable economic merit should by itself provide an adequate justification for the project.

In the negative case, primary and direct impacts are the main concern. They are often termed "environmental" but environment, amenity and socio-economic features are closely interlinked and the distinction between them becomes largely a matter of definition. Costs can result, for example, from the flooding or excessive drainage of residential or agricultural land, from water retention and abstraction and from disturbance created by the construction and operation of the plant. They can affect housing, employment and livelihood of the local population and they can impair the natural environment, flora and fauna. As in the positive case, impacts are largely intangible but they are nevertheless real and can be of sufficient weight to influence a decision for or against a project proposal.

The decision-making process can also be affected by outside parties for whom the area envisaged for the project is of special recreational, historical or conservational importance. Indeed, differences of perception can arise: the local population may see the scheme as a provider of benefits whreas external groups may fear its disturbing effect on environment and amenity and may wish the project to be abandoned. Secondary and indirect costs may then have to be set against primary and direct benefits, a situation which cannot always be resolved by impact appraisal alone and which may require a policy decision or directive. In the industrialised world, prolonged negotiations between the interested parties, public enquiries and referenda can be involved, even for relatively minor developments. Many hydro proposals have foundered in these circumstances. There is less sensitivity on these issues in the developing countries because of greater urgency for basic services, lower population densities and a greater reservoir of undeveloped resources but there can be no doubt that sensitivities will become more acute in the future and that the assessment of socio-economic costs will then become a more important element in hydropower planning. For the time being, such costs are likely to outweigh the benefits only in special circumstances.

The benefits which might be achieved from electrification will depend on the ability of the consumers to purchase the requisite amounts of electricity. People still relying largely on a subsistence economy may not be able to buy sufficient electricity to realize the expected positive impacts. Price-demand resilience will govern power market formation and expansion. Consumers will be particularly sensitive to the elctricity price in the early stages of their connection to a supply. Consumer reaction to the tariff rates that may have to be charged should be assessed prior to electrification, not only to arrive at a more realistic appraisal of positive impacts but also for estimating potential revenues and subsidisation needs and for determining from what sources subsidies might be drawn. If the project is to be self-subsidising, i.e. if the revenues from selling the output of the scheme are anticipated to fall short of the costs of supply - production and distribution costs - the distributor will have to decide whether

- the income from his operations generally will be sufficient to subsidise the supply from the new scheme, or
- subsidies can be obtained from other sources, e.g. the government, or
- the irrecoverable element of the project costs should be capitalised and debited against the project and its economic merit reduced accordingly.

The latter procedure is used only rarely because most utilities can subsidise rural consumption with income surpluses from urban centres or they can enlist government support in aid of rural development.

Quantification of Impacts

It is largely a matter of judgement to decide which socio-economic impact is significant for a hydropower development and which is not. Even a small scheme can have a number of primary and consequential secondary impacts and a priority ranking will have to be established in order to keep the analysis within bounds. It is probably not worth considering more than about 12 to 15 separate socio-economic features in the analysis of a small project. If these features are to figure in the economic appraisal, they must be expressed in numerical terms and used to increase or decrease the economic benefits computed for the scheme. If the features are not valued and remain a matter of argument or conjecture, development decisions can become arbitrary and exposed to the opinion of decision-makers or pressure groups. Such a situation is probably more serious for larger projects which have greater environmental impact and cause more apprehension but small schemes are not immune. Disturbance of breeding grounds, interference with fish life and recreational amenity and even minor intrusion on residential or agricultural land can produce a climate in which it becomes difficult to pursue a development proposal, regardless of its intrinsic merit.

Quantification of adverse effects, though difficult and often subjective, will help developers to put such effects into proper relation with quantified benefits and thereby overcome preconceptions based on argument alone. Some features, ecological damage for example, do not seem to lend themselves to numerical assessment and will have to be dealt with by empirical appraisal. An attempt can however be made in many cases to support this appraisal with facts and figures, even if they work ultimately to the detriment of the project. An adverse decision will then at least be taken on firm ground. It needs to be kept in mind that, if a project can be shown to meet a demand and to be of merit, the potential consumer will be disadvantaged if the project is not built and he will suffer a negative impact. Electricity prices may have to rise if a less favourable, and maybe less contested, solution has to be adopted. The adverse effect of higher costs and prices will have to be set against the disadvantages which the objectors claim to have identified so that a fair estimate of the real cost of a particular solution can be made and gains and losses properly balanced.

Some negative impacts are routinely quantified and included in the project appraisal or at least taken into account in decision-making. These are mainly the direct consequences of introducing a hydro scheme into a populated and economically active area, even if the economy is close to a subsistence level. Examples are the needs for resettlement because of displacement by the scheme, compensation payments for loss of water or employment, loss of or interference with local livelihood and restitution for land taken over for the scheme. Such cases can be valued fairly readily; proper valuation and acceptance by the affected parties is usually a pre-condition for development consent. The arrangements agreed to will impose a predictable financial burden on the project. The expenditure can be included as an item in the construction cost; only occasionally is it debited against the economic benefits. It does not figure in the socio-economic impact analysis but can be used as a yardstick for the valuation of other impacts. The developer can also pay for this expenditure out of his revenue, particularly in cases where compensation payments are involved; these amount often to annual rather than capital disbursements. The costs are then spread over all the consumers supplied by the developer and not only over those benefitting from the new scheme. This kind of allocation amounts to a hidden subsidy for the new consumers.

The majority of the impacts are difficult to quantify, largely because their effect is less immediate and less tangible. If these features are to figure in the project appraisal, they need to be valued on a comparative basis against parameters for which a monetary value can be better estimated. Examples of such parameters are

- changes in land use
- housing or re-housing requirements
- creation of employment or unemployment
- changes in local economic activity, in the widest sense
- resulting changes in income levels and fiscal contributions.

Some of these parameters are evaluated in connection with the compensation arrangements referred to above. If they are used as a yardstick for the numerical appraisal of other impacts, care needs to be taken to avoid double-counting. Most of these impacts act at a local level. Their effect at the national level will develop gradually and will be more difficult to identify and estimate because it will overlap with impacts arising from other activities in different areas. This is particularly so with employment creation and stimulation of the economy which can result from electrification but by no means from electrification alone.

Impacts which are more difficult to value in monetary terms include

- soil improvement or degradation (due to drainage, flooding, leaching, silting or de-silting)
- changes in water conditions in rivers and storage reservoir
- disturbance of environment and ecology
- reduced deforestation
- changes in social conditions
- effects on the infrastructure.

For the numerical appraisal of socio-economic benefits and costs (or "disbenefits"), a matrix can be set up in which the value of each quantified impact is shown on a monetary scale - both positive and negative. The annual or annuitised values of the more readily quantifiable impacts are entered first since they provide a basis for the valuation of the less tangible parameters. A value based on experience and local investigation is then assigned to the more important of the "difficult" impacts and also entered into the matrix. A trial-and-error approach will probably be necessary to ensure that all the values shown in the matrix stand in a reasonable relation to each other. A scatter of points is obtained which represents the benefits and costs computed for the project. Summation of the values given by these points will present an overall estimate of the more important socio-economic impacts in monetary terms which, when capitalised, can be used directly in the economic appraisal. Capitalisation is necessary where the values are annually recurring figures and also where there are differences in the time incidence of the various impacts. Cost streams - or rather streams of monetary values - can also be present-valued as they are estimated and the corresponding capitalised figures entered into the matrix. Summation of these figures will then produce an overall benefit or cost item for inclusion in the economic appraisal as previously described. Changes in assumptions about the nature or size of the impacts can be tested by sensitivity analysis and confidence limits can be established within which the aggregate worth of the socio-economic impacts is expected to lie.

An example of a socio-economic matrix is shown in Figure 1. Twelve items are included involving features varying in difficulty of valuation. Each item presents the result of a detailed impact study. An alternative presentation of the same information is given in Figure 2 where each impact is valued on an arbitrary scale in accordance with its severity. The scale is chosen to place the quantified impacts into proper relation with the size and cost of the project.

These procedures involve a great deal of judgement, not only in quantifying particular impacts but also for deciding which impacts are to be included in the assessment and how far secondary effects should be pursued. The exercise can result in much work. There must be reasonable conviction that the effort is worth while and that adequate funds for it can be made available. It may be argued that the costs should not be charged to the preparatory work for the particular project alone. They should be allocated, at least in part, to national energy sector management as a whole, on the premise that the socio-economic aspects of the project will contribute to the overall development of this sector and not exclusively to that of the immediately affected area. Financing institutions may well wish to consider this approach which would greatly facilitate the funding of more extensive socio-economic studies.

Impacts which were not taken into account in the initial assessment may well become more prominent some time after the project has come into service; this could be the case particularly with the slowly developing secondary impacts. A retrospective review might then show that the initial planning decision could have been taken on a better basis, an experience by no means confined to hydropower alone. The danger of an initially intangible factor outweighing an economic merit which was seemingly well established in the project planning stage will be greatest for borderline cases showing a very low economic return. Events other than socio-economic impacts could have a similar effect, for example changes in water run-off resulting from long drought periods or some geophysical events, population movement away from an isolated project area or even economic stagnation. Every investment decision entails a risk. This risk is minimised if all the consequences are carefully evaluated at the outset but this can only be done on the facts available at that time. The procedure here advocated offers an assurance that some of the more intractable consequences of a development proposal are taken into account at the planning stage and that the benefits of small-scale elctrification in rural and outlying areas are not overlooked. These matters are of particular importance for the developing countries.

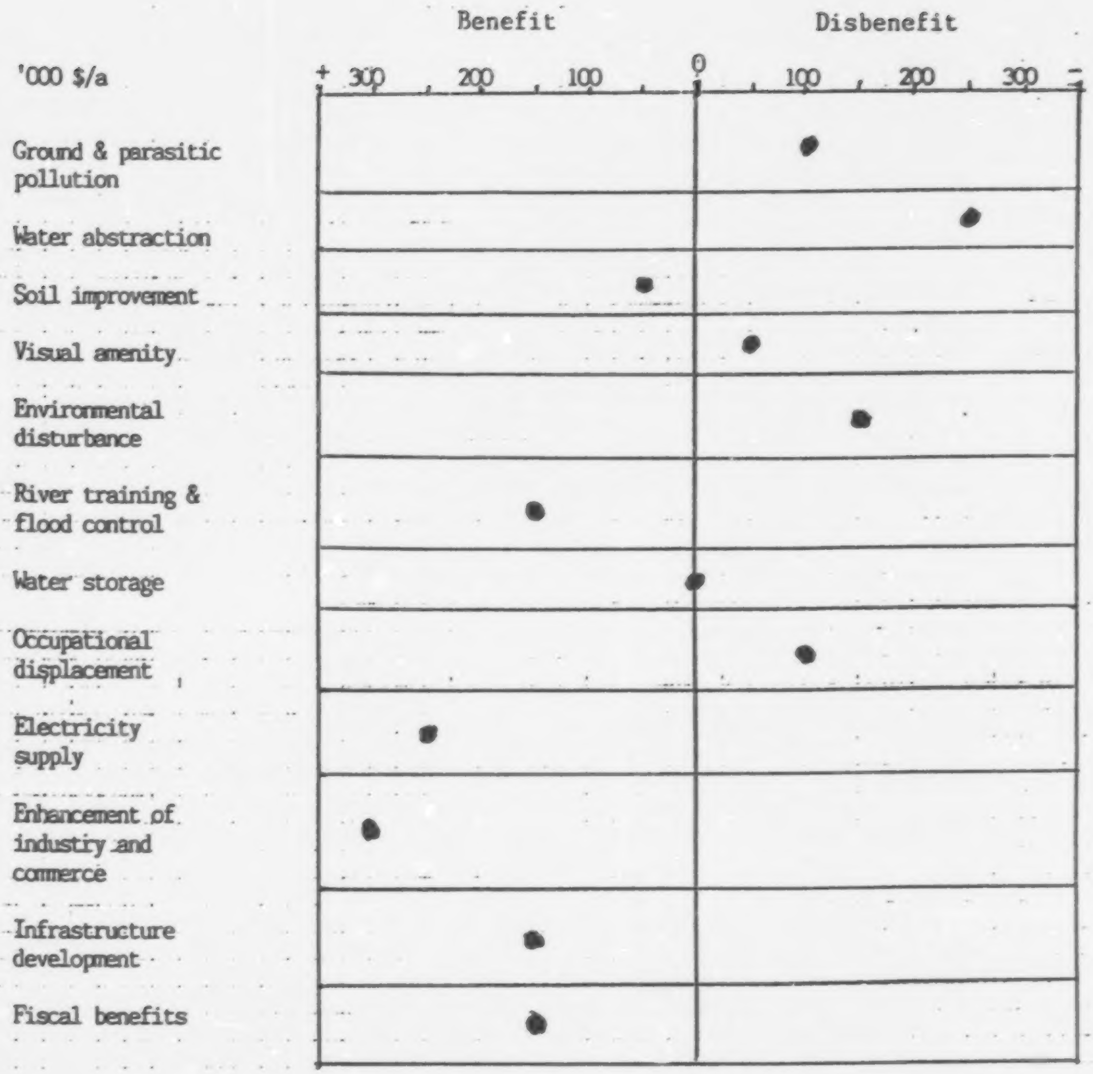
Different methodologies are available for the comparative analysis and quantification of socio-economic impacts. They are mostly similar to the matrix approach. Computer techniqies can be used for setting out a spectrum of probable values for each major impact and then determining their aggregate value in terms of probability. Bearing in mind that identification, clasification and valuation of impacts will all be highly subjective, it is perhaps not justified to employ unduly sophisticated methods of analysis. The derivation of the final results must be transparent and credible. Developers and financing institutions will want to be convinced that any modifications of the economic merit as computed by conventional project appraisal are on firm gound.

Conclusions

The purpose of this paper is to highlight the role which socio-economic impact analysis can and should play in the project appraisal process for small-scale hydropower. Positive or beneficial impacts are likely to predominate in the outlying areas of the developing countries. Quantification of such impacts can have a considerable effect on the merit of a project which is often only marginal because of high construction costs and an uncertain and fluctuating hydrology which may require firming up with costly thermal power. Part of the justification for a hydro scheme as a means of substituting energy from indigenous sources for imported energy is lost if imported fuel continues to be needed. This situation affects the majority of the small schemes examined under the United Nations hydropower programme. Unless socio-economic considerations are also taken into account, many potentially promising schemes will be set aside, to the detriment of the development of the countries concerned. Socio-economic impact analysis should therefore play an essential role in the project development process. It should encourage financing institutions not to interpret economic merit too narrowly and to take account of the wider benefits which decentralised power production can bring.

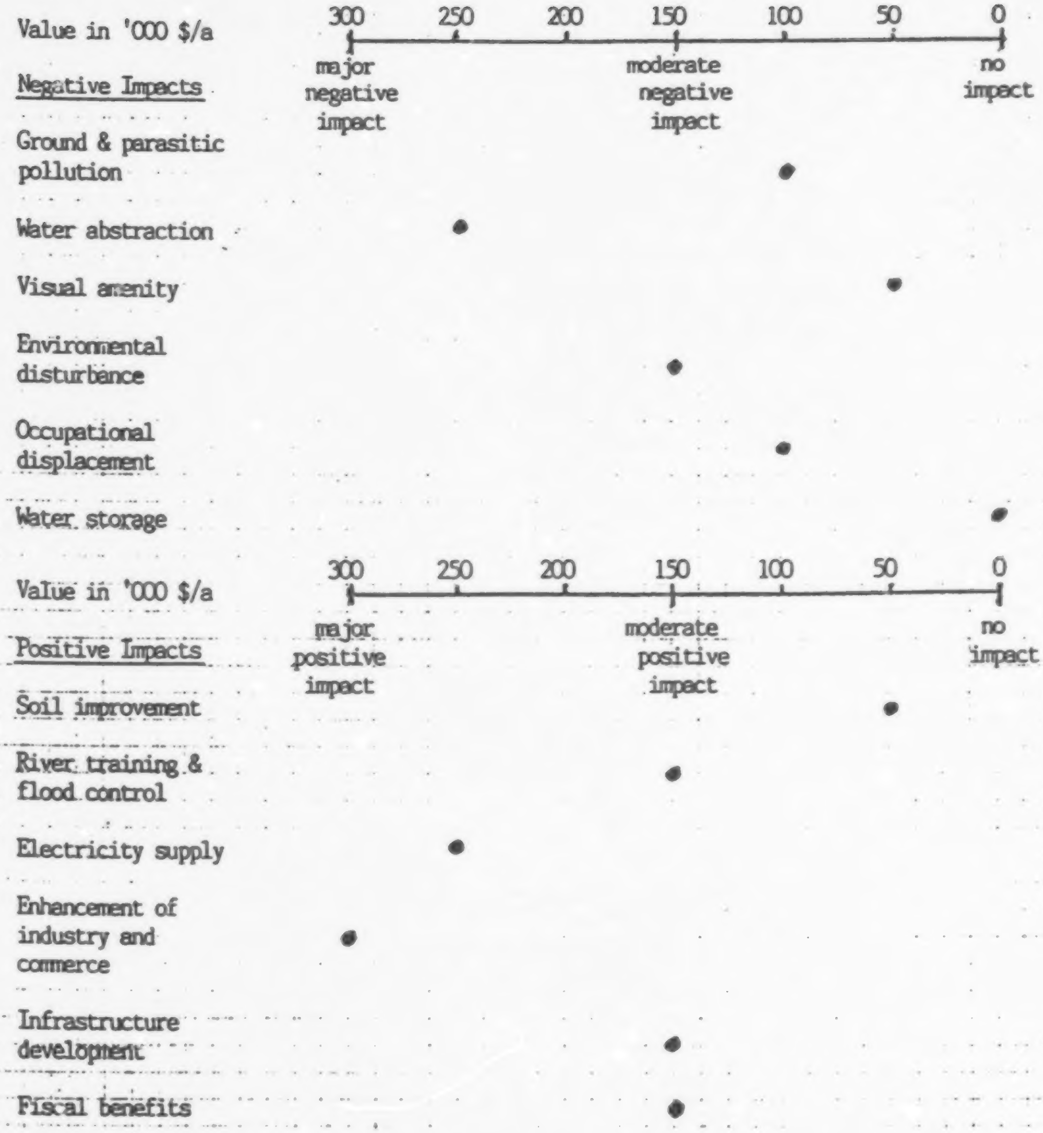
Assessment of negative impacts should not rely on conjecture, especially in cases where a project which some parties find disturbing will bring considerable benefits to others. Quantitative evaluation can do much to overcome perceived impressions and may help to mitigate the pressure exerted by special interest groups. If offset against positive impacts, it may offer a more realistic appraisal of the true merit of a given proposal. This could be of importance in industrialised countries where a number of small hydro projects have run into difficulty for a variety of non-technical reasons.

When advocating that more attention should be paid to socio-economic impact analysis, it is necessary to keep in mind that the analysis involves the quantification of features which are difficult to assess in monetary terms. Judgement will inevitably come into play and this may raise questions on the validity of an essentially subjective approach. As methods of analysis become more extensively developed, experience in valuation procedures will be built up and the approach will become less empirical. For the present, the analysis should concentrate on major features for which factual information can be more readily established; their valuation alone could mark significant progress in project appraisal.



Net benefit = US$ 400,000 p.a.

FIGURE 1. SOCIO-ECONOMIC MATRIX



Net benefit = US$ 400,000 p.a.

FIGURE 2. SOCIO-ECONOMIC SCALE DIAGRAM

SESSION 4:

REGULATORY ISSUES

Chairperson: F. Springer
Federal Energy Regulatory Commission

Effects of FERC Implementation of the Electric Consumers Protection Act on United States Hydropower Development

By
W.B. Smith

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EFFECTS OF FERC IMPLEMENTATION OF THE ELECTRIC CONSUMERS PROTECTION ACT ON U.S. HYDROPOWER DEVELOPMENT

by

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EFFECTS OF FERC IMPLEMENTATION OF THE ELECTRIC CONSUMERS PROTECTION ACT ON U.S. HYDROPOWER DEVELOPMENT

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ABSTRACT

Since the passage of the Electric Consumers Protection Act (ECPA) in October 1986, the hydropower industry in the United States has seen a steady and rapid decline in the development of new hydroelectric projects, both in the private and public sectors.

One major purpose of the ECPA is to amend Section 4(e) of the Federal Power Act to give equal consideration to power and development purposes and to the purposes of:

- energy conservation;
- the protection, mitigation of, damage to, and enhancement of fish and wildlife;
- protection of recreational opportunities; and
- preservation of other aspects of environmental quality.

A major reason for the dramatic impact of ECPA is that the law significantly increased the regulatory burden on the hydropower industry. Confusion by the Federal Energy Regulatory Commission (Commission) and the federal, state, and local environmental agencies in interpreting specific sections of the ECPA have led to policy changes that are conflicting. ECPA has raised serious jurisdictional questions between state and federal authority.

Following passage of ECPA, the Commission has issued three Final rulemakings, two Interim rules, and three Notice of Proposed rules to implement ECPA. The majority of the new or proposed rulemakings involves procedural issues. Some examples of these procedures which will affect the Licensee are summarized below:

- The Licensee is to reimburse FWS, NMFS, and state agencies for costs incurred in setting mandatory terms and conditions on hydropower licenses.
- The Licensee must make public all existing data relating to the construction and operation of their existing project, once the notice of intent to file an application for a new license is accepted.
- The Licensee must satisfy three new environmental conditions for projects located at a new dam in order to qualify for PURPA benefits.

(1) The Commission must find that the project will not have substantial adverse effects in the environment.

(2) The project can't be located in an existing or potential state or national wild and scenic river system, or in a natural watercourse which the state has determined to possess unique, natural recreational, cultural, or scenic attributes which would be adversely affected by hydroelectric development.

(3) If justifiable, the project must meet the terms and conditions set by fish and wildlife agencies under the same procedures provided for under Section 30(c) of the Federal Power Act.

o New regulations related to relicensing of existing projects to resolve the enhancement of fish and wildlife issues, etc.

The purpose of this paper is to review, from the industry perspective, these and other proposed or final rulemakings issued by the Commission since the enactment of ECPA and to summarize the impact which these rulemakings have and will have on the U.S. hydropower industry.

DESCRIPTION OF ECPA

On October 16, 1986, during the 99th Congress, Public Law 99-495 was enacted. The purpose of the Electric Consumers Protection Act (ECPA) was to amend the Federal Power Act to provide more protection to electric consumers. The act was entitled "The Electric Consumers Protection Act of 1986." The ECPA Act consisted of 17 sections which amended 12 sections of the Federal Power Act. Summarized below are the 17 sections of ECPA.

Section 2 made minor amendments to the Section 7 language of the Federal Power Act.

Section 3 amended Section 4(e) of the Federal Power Act to require that in addition to the power and development purposes for which Commission licenses are issued, equal consideration to the purposes of energy conservation, the protection, mitigation of, damage to, and enhancement of, fish and wildlife, the protection of recreational opportunities, and the preservation of other aspects of environmental quality.

Section 3 also amended Section 10a of the Federal Power Act to consider project development being consistent with comprehensive plan, considering recommendations of federal and state agencies, and considering Electric Consumption Efficiency Improvement Program.

Finally, Section 3 required consideration of fish and wildlife protection, mitigation, and enhancement, and amended Section 10 of the Federal Power Act.

Section 4 addresses the relicensing process and amends Section 15 of the Federal Power Act. This section addresses preference issues in relicensing, enhancement of fish and wildlife issues, public information required for existing data at time of filing, and filing requirements.

Section 5 addresses the license term of relicensing and amends Section 15 of the Federal Power Act.

Section 6 amends Section 23(b) of the Federal Power Act with clarification of authorized and unauthorized activities at a project site.

Section 7 amends Section 30 of the Federal Power Act and adds a fee structure for studies required under Section 30 to reimburse fish and wildlife agency costs.

Section 8 amends Section 210 of the Public Utilities Regulatory Policies Act (PURPA) of 1978. This amendment adds requirements relating to (1) no substantial adverse effects, (2) protected rivers, (3) fish and wildlife terms and conditions, (4) establishes exceptions, creating a transition rule for projects in process, and (5) establishes a study to be prepared by the Commission in accordance with the National Environmental Policy Act of 1969 (NEPA) as to how PURPA should be applied to hydroelectric facilities utilizing new dams and diversions.

Section 9 amends Section 10(e) of the Federal Power Act in establishing fees for use of government dams and formulates a method for calculating these fees.

Section 10 of ECPA applies to relicensing proceedings for specific projects.

Section 11 is an amendment specifically exempting the Merwin Dam Project, FERC Project No. 2791, from ECPA.

Section 12 creates a new Section 31 entitled "Enforcement," which is added to the Federal Power Act and addresses monitoring and investigation, revocation orders, civil penalties, and assessment.

Section 13 of ECPA relates to anti-trust laws and amends Section 10(h) of the Federal Power Act.

Section 14 relates to landowner notification and amends Section 9 of the Federal Power Act which provides notification to landowners and federal, state, or local agencies interested in an application.

Section 15 amends Section 211(c) of the Federal Power Act and relates to applications for certain orders under the Federal Power Act and to modification of existing rate structures.

Section 15(a) covers miscellaneous provisions that apply to specific hydroelectric projects in the United States.

Section 16 provides a mandate for the Commission to provide information to Congress.

Section 17 is a savings provision act which maintains the integrity of previously established authorizations.

The following table is a cross reference between sections of the Federal Power Act (FPA) and the ECPA sections which were enacted to modify the FPA. It also indicates the sections of the FPA which have been modified or are proposed to be modified by the Commission through Final Rules (F), Interim Rules (I), and Notice of Proposed Rules (NOPR). The remaining sections of the FPA have yet to have action taken by the Commission to implement ECPA or are not required by law to take action.

Federal Power Act	ECPA	Commission Action
Section 4E	Section 3	-
Section 7A	Section 2	-
Section 9	Section 14	F
Section 10	Section 3	-
Section 10A	Section 3	Issued per ECPA
Section 10E	Section 9	-
Section 10H	Section 13	I & NOPR
Section 15	Section 4 and 5	-
Section 23B	Section 6	F
Section 30	Section 7	NOPR
Section 31	Section 12	NOPR
Section 211C	Section 15	Not Required

In addition to modifying the Federal Power Act, Section 8 of ECPA amended Section 210 of PURPA. This section added a new subsection, 210(j), which addresses new dams and diversions. An Interim Rule and a NOPR have been issued on this section.

FERC RULEMAKINGS

Since the enactment of ECPA on October 16, 1986, the Commission has been responsible for the interpretation of Congressional intent through new rulemakings. A variety of Notice of Proposed Rules (NOPR), Interim Rules, and Final Rules have been released by the Commission beginning in early 1987. This section of the paper will describe these NOPRs, Interim Rules, and Final Rules as issued by the Commission and published in the Federal Register.

FINAL RULES

Docket No. RM 87-6-000: Fees for hydroelectric project applications to reimburse fish and wildlife agencies. Issued December 16, 1987. Implements Section 7(c) of ECPA.

Summary: Rule requires hydroelectric license and exemption applicants for projects that are required to meet terms and conditions of fish and wildlife agencies under Section 30(c) of the Federal Power Act (FPA) to reimburse those agencies for any reasonable costs incurred in connection with studies or reviews they carry out in setting mandatory terms and conditions to project fish and wildlife resources.

Agencies Affected: Agencies to be reimbursed under this rule are U.S. Department of Commerce, National Marine Fisheries Service (NMFS); U.S. Department of Interior, Fish and Wildlife Service (USFWS); and the state agency responsible for fish and wildlife resources.

Background: Prior to ECPA, two categories of applicants were subject to terms and conditions of fish and wildlife agencies under Section 39(c) of FPA. These were applicants for exemptions from licensing under Section 30 of FPA (conduit exemptions) and applicants for exemptions from licensing requirements under Sections 405 and 408 of PURPA (5-MW exemptions).

Overview: Under this rule, a prospective new dam or diversion license applicant must inform each fish and wildlife agency, in writing, whether it will seek PURPA benefits. Also, a prospective applicant seeking exemption from licensing must notify each fish and wildlife agency of its intent to seek exemption. During the comment period of the second stage consultation process, a fish and wildlife agency will provide an applicant with an estimate of costs which the agency will incur in setting mandatory terms and conditions. The application to the Commission must include the latest cost estimate of the agencies, including updates and a cash payment of 50 percent of estimated fees or a bond for 100 percent of estimates fees. The application will be rejected without appropriate cash amount or bond.

Within 60 days after date for setting mandatory terms and conditions, or 60 days after application is withdrawn, rejected, or dismissed, a fish and wildlife agency must file with the Commission a final statement of costs. After receiving statement, the Commission will submit a bill to applicant stating amounts to be paid by, or refunded to, the applicant.

Amounts owed must be paid within 45 days after the bill is issued or, within the same time frame, the U.S. Treasury will refund overpayments. The Commission will not grant license or exemption until full amount of fee is paid.

Effective Date: The Final Rule was effective January 21, 1988.

Industry Perspective of Final Rule: Generally, the hydropower industry supported the Commission's efforts to implement the fees requirement contained in the ECPA. The federal and state agencies generally believe the Commission did not adequately consult federal and stage agencies and they believe the proposed fee system is administratively and fiscally unworkable.

Industry representatives argued that the fees should not be retroactively applied and should become effective after the rule's effective date. Federal and state agencies argued that the fees be retroactive, that agencies should be reimbursed for some or all costs, even if an application is never filed. The Commission ruled in favor of the hydropower industry in all of these issues.

Federal agencies commented that costs incurred after a license or exemption is issued, such as monitorings, compliance, and enforcement, should be reimbursed. The Commission determined these financial obligations were not intended by ECPA and such costs would be undeterminable and place an inordinate burden on hydropower developers.

Industry representatives proposed a standard filing fee or establishment of schedule of payments with a fee ceiling in order to determine a maximum fee liability. The Commission determined such fee structuring is not possible to be established at this time; however, as the Commission gains experience, it will consider whether standard fees or a fee ceiling are appropriate.

Industry representatives argued that the up-front 50% payment was unduly burdensome. The federal agencies suggested a 75% up-front payment as more appropriate. The resulting decision was for a 50% cash payment or 100% surety bond (proposed by Small Business Administration).

Other issues reviewed in developing the Final Rule included time periods for final mandatory terms and conditions, accountability for cost estimates, review procedures, dispute resolution, adjustments of annual charges, and cost reimbursement procedures.

* * * * *

Docket No. RM 87-32-000: Requirements of landowner notification. Issued September 30, 1987. Implements Section 14 of ECPA.

Summary: The rule requires an applicant for a hydroelectric license (other than a new license under Section 15 of FPA) to make a good faith effort to notify, by certified mail, (1) any person who is an owner of record of any interest in the property within the project boundary and (2) any federal, state, municipal, or other local government agency likely to be interested in or affected by such application.

Background: Under current Commission regulations, an applicant for a preliminary permit or an initial license is required only to identify in the application certain individuals or government entities that might be affected by the project. Once the application is accepted for filing, notice of the proposed project is published once a week, for four consecutive weeks, in a local newspaper. Additionally, the Commission notifies, in writing, any state of municipality (city, county, irrigation district, or other political subdivision or agency of a state competent to carry on business of developing, transmitting, utilizing, or distributing power) likely to be interested in or affected by the application.

Concern that publication in a local newspaper sometimes did not notify absentee landowners of the proposed project led Congress to add a landowner notification provision to ECPA.

Overview: The new regulation requires applicants for licenses, other than FPA Section 15 licenses, to make a good faith effort to notify, by certified mail, certain property owner and government entities. An application for such license must contain a statement that the application has made this effort either at the time of or before filing of the application.

The applicant must notify every property owner of record of any interest in the property within the bounds of the project, or for projects without a specific boundary, any owner of property which would underlie or be adjacent to the project works, including any impoundments. Additionally, the applicant must make similar effort to notify the following:

1. Every county in which any part of the project and any federal facilities that would be used by the project would be located;

2. Every city, town, or similar local political subdivision:

    a. in which any part of the project and any federal facilities that would be used by the project would be located; or

    b. that has a population of 5,000 or more people and is located within 15 miles of the project dam;

3. Every irrigation district, drainage district, or similar special purpose political subdivision:

    a. in which any part of the project and any federal facilities that would be used by the project would be located; or

    b. that owns, operates, maintains, or uses any project facilities or any federal facilities that would be used by the project;

4. Every other political subdivision or federal, state, municipal, or other local government agency in the general area of the project that there is reason to believe would be interested in, or affected by, the application.

Notification must contain the name, business address, and telephone number of the applicant and a copy of Exhibit G - Map of the Project, as contained in the application. The notice must also state that a license application is being filed with the Commission.

Effective Date: This rule implements notification requirements contained in ECPA. As such, it became effective 30 days after publication in the *Federal Register* (October 6, 1987), provided OMB has approved this rule.

Industry Perspective of Final Rule: Since this final rule was effective under the Administrative Procedure Act, it is exempt, as an interpretative rule, from both public notice and comment requirements. The industry generally does not oppose the requirement, though additional effort, time, and cost will be incurred by a license applicant.

* * * * *

Docket No. RM 87-36-00: Interpretation of comprehensive plans for "improving, developing, or conserving a waterway or waterways affected by the project." Issued October 20, 1987. Implements Section 3(b)(4) of ECPA.

Summary: This rule amends Section 10(a) of the Federal Power Act to require the Commission to consider, in issuing a hydroelectric license, the extent to which the proposed project is consistent with an existing federal or state comprehensive plan for "improving, developing, or conserving a waterway or waterways affected by the project." In this rule, the Commission defines a "comprehensive plan" and establishes guidelines for developing these plans.

Overview: The Commission has always been required to ensure that under Section 19(a) of the FPA that the project adopted will be, in the judgment of the Commission, best adapted to a comprehensive plan for improving or developing a waterway or waterways for the use or benefit of interstate or foreign commerce for the improvement and utilization of waterpower development and for other beneficial public uses.

The U.S. Supreme Court has interpreted Section 10(a) as requiring the Commission to explore "All issues relevant to the public interest."

When the Commission acts on a license application, the entire record developed in the proceeding by which the Commission evaluates the application constitutes the Section 19(a) comprehensive plan. This record is developed by the applicant, Commission staff, intervenors, commenting federal, state, and local agencies, and other concerned parties. The Commission then integrates and balances various public interests to optimize the improvement and utilization of the waterway for beneficial public purposes. Any licensing decision of the Commission must be supported by substantial evidence.

This rule specifies certain public interest factors that the Commission is to consider in the license decision process, including a new paragraph to Section 10(a) which describes the extent to which a proposed project must comply with any existing federal or state comprehensive plans. State plans must have been prepared and adopted pursuant to a specific Act of the state legislature and developed, implemented, and managed by the appropriate state agency.

Many of the comprehensive plans currently submitted to the Commission consider only limited uses of the waterway. Many of these plans do not include substantial facts, studies, and technical evidence necessary to allow the Commission to understand and independently evaluate the state's conclusions. This rule outlines general guidelines for developing these plans. Under this rule, a comprehensive plan should contain the following:

1. A description of waterway (which may include a river segment, river basin, drainage area, or other geographical area), or waterways that are the subject of the plan, including pertinent maps detailing the geographic area of the plan.

2. A description of the significant resources of the waterway or waterways.

3. A description of the various existing or planned uses for these resources.

4. A discussion of goals, objectives, and recommendations for improving, developing, or conserving the waterway or waterways in relation to these resources.

The description of significant resources identified in Item 2) above should include: (a) navigation; (b) power development; (c) energy conservation; (d) fish and wildlife; (e) recreational opportunities; (f) irrigation; (g) flood control; (h) water supply; and (i) other aspects of environmental quality. The description of existing and planned uses identified in Item 3) above should include a description of currently unused areas of waterway and any future plans for the areas and advantages and disadvantages associated with each planned use.

In establishing goals, objectives, and recommendations as identified in Item 4) above, the plan should contain an examination of how different uses will promote the overall public interest, the goals the plan expects to achieve, and an analysis of how specific recommendations of the plan further those goals.

Effective Date: This rule states the Commission's interpretation of a federal or state comprehensive plan and, as such, becomes effective 30 days after publication in the Federal Register (October 26, 1988), provided OMB has approved this rule.

Industry Perspective of Final Rule: Since this Final Rule was effective under the Administrative Procedure Act (APA), it is exempt, as an interpretative rule from both public notice and comment requirements. However, on April 27, 1988, the Commission issued an Order on rehearing its Final Rule as a result of various state agency petitions for rehearing requests. The petitioners argued that the Final Rule does not fall within the interpretive rule exception to the APA. They argue that the rule imposed requirements for these plans that were not contained in ECPA, thus the rule was not interpretive.

The Commission will treat as a comprehensive plan under Section 10(a)(2)(A) of the FPA a plan that (1) is prepared by an agency established by federal law that has the authority to prepare such a plan, or by a state agency authorized to conduct such planning pursuant to state law; (2) is a comprehensive study of one or more of the beneficial uses of a waterway or waterways; (3) articulates the standard applied, the data relied upon, and the methodology used; and (4) is filed with the Secretary of the Commission.

Because this Order constitutes a new policy with respect to comprehensive plans under Section 10(a)(2)(A) of the FPA, the Commission instructs the Director, Office of Hydropower Licensing, to mail a copy of this Order to all state governors and appropriate federal agencies. The Director will request the states and federal agencies to file with the Commission the plans they believe meet the policy criteria set forth in this Order. The Director will, within a reasonable period of time, advise the filer whether a plan meets the policy criteria, and if not, why not. If necessary in order to make a determination, the Director may ask the filer to submit additional information with respect to a plan. The Commission staff will also be available, on request, to discuss comprehensive planning with state and federal personnel.

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INTERIM RULES

Docket No. RM 87-7-000: Information to be made available by hydroelectric licensees to the public upon notification to the Commission of the intention to file for a "new" license. Issued March 30, 1987. Implements Section 4(a) of ECPA.

Summary: To promote competition in the relicensing process, this rule establishes new procedures, timetables, and standards for relicensing proceedings. A new Section 15(b)(1) requires an existing Licensee to notify the Commission at least five years before the expiration of its license whether or not the Licensee intends to file an application for new license.

The new Section 15(b)(2) requires a Licensee, upon notification of intent to file, to make reasonably available, at its offices, to the public for inspection, current maps, drawings, data, and such other information as the Commission shall require regarding the construction and operation of the licensed project. Copies of such information, including pertinent energy conservation, recreation, fish and wildlife, and other environmental data, shall be made available by the existing Licensee at reasonable reproduction costs.

The new Section 15(b)(3) requires the Commission to provide public notice and notify fish and wildlife agencies of an existing Licensee's intention to file or not to file an application for a new license. Section 15(c)(1) requires an existing Licensee or a competitor to file an application for a new License with the Commission at least 24 months before the expiration of the existing license. Section 15(c)(2) authorizes the Commission to adjust, by rule or order, the time periods when existing licensees of nine specific projects described in Section 10 of ECPA are unable to comply with specified time period because of existing expiration date of their licenses.

Overview: The existing regulations (pre-ECPA) require an existing licensee to file an application for a new license or statement of intention not to file, no earlier than five years and no later than three years before expiration of its license. A competitor can file an application for new license within five years before the expiration of the existing license, and the competitor may not file an application later than six months after issuance of the public notice of the filing of an application or statement by the existing licensee or 2-1/2 years before expiration of the existing licensee, whichever is earlier.

The new rule requires an existing licensee or competitor to file an application for a new license no later than two years prior to expiration of the existing license. The new rule also requires the existing licensee to notify, in a letter containing an unequivocal statement, the Commission of its intention to file or not to file an application for a new license.

The Commission believes the provisions of this rule, regarding certain information be made available for public inspection and reproduction, are intended to facilitate public access to information relating to current and past operation and construction of the existing licensee's project. Future plans of a license are not part of this public information disclosure, in order to maintain proprietary information until the new license is filed. The Commission requires that information pertaining to project generation and operation and maintenance problems and costs is to be provided for the last five years preceding the time information is required to be made available to the public. However, the Commission encourages existing licensees to make information from prior periods available if a request for information is made by the members of the public. Both developmental (relating to construction and operation) and non-developmental (relating to project's impact on the environment) criteria were considered in determining what information must be made available to the public.

The Commission requires the following information be made available under the categories of construction and operation, safety and structural adequacy, fish and wildlife resources, energy conservation, recreation and land use resources, and cultural resources:

1. Construction and Operation

   a. the original license application and the Order Issuing License for the Existing Project, including approved and as-built Exhibit F drawings, all orders issuing amendments to the license for the existing project, and all orders issuing annual licenses for the existing project;

   b. all data necessary to enable the public to verify that the project has been and is being operated in accordance with the requirements of each license article, including minimum flow requirements, maximum ramping rates, reservoir elevation limitations, and environmental monitoring;

   c. a compilation of project generation and respective outflow data with time increments not to exceed one hour for the previous five years;

   d. all public correspondence relating to the existing project;

   e. all existing reports showing the total actual annual generation and annual operation and maintenance costs for the previous five years, original project costs, and current net investment;

   f. a current and complete electrical single-line diagram of the project showing the transfer of electricity from the project to the area utility system; and

g. all bills issued to the existing licensee by the Commission for annual charges under Section 10(e) of the FPA.

2. Safety and Structural

a. the most recent emergency action plan for the project or a letter exempting the project from the emergency action plan requirements;

b. all independent consultant's reports, if required by Part 12 of the Commission's regulations, filed subsequent to January 1981;

c. all existing reports on any operation or maintenance problems, other than routine maintenance, occurring within the last five years, and associated costs of such problems under the Commission's Uniform System of Accounts;

d. the final construction report (or reports if construction occurred in more than one phase) for the existing project; and

e. all public correspondence relating to the safety and structural adequacy of the existing project.

3. Fish and Wildlife Resources

a. all existing reports documenting impacts of the project's construction and operation on fish and wildlife resources;

b. all existing reports documenting the presence or absence of any threatened or endangered species and critical habitat located in the project area, or impacted by the existing project;

c. all fish and wildlife management plans prepared by the existing licensee or resource agency related to the project area; and

d. all public correspondence relating to fish and wildlife resources within the project area.

4. Energy Conservation

   a. if the existing licensee is an electric utility, or a state or municipality that uses any of the power generated by the existing project itself, its plan to conserve electricity or encourage conservation by its customers; and

   b. all public correspondence concerning energy conservation measures related to the existing project.

5. Recreation and Land Use Resources

   a. all existing reports on past and current recreational uses of the project area;

   b. all existing maps which show recreational facilities and areas reserved for future development in the project area, designated or proposed wilderness areas in the project area, Land and Water Conservation Fund lands in the project area, and designated or proposed wild and scenic river corridors (state and federal) in the project area;

   c. documentation showing the entity or entities responsible for operating and maintaining any existing recreational facilities in the project area; and

   d. all public correspondence relating to recreation and land use resources within the project area.

6. Cultural Resources

   a. all existing reports concerning documented archeological resources identified in the project area;

   b. all existing reports documenting historical and present utilization of the project area and surrounding areas by Native Americans; and

c. all public correspondence relating to cultural resources within the project area.

Section 15(b)(2) of the FPA requires an existing licensee to make the required information reasonably available. The Commission requires an existing licensee to make the required information available in a form that is readily accessible, reviewable, and reproducible.

The Commission is requiring an existing licensee to make the required information available to the public for inspection and reproduction at the licensee's principal place of business during regular business hours.

The Commission is requiring an existing licensee to make available, upon request, a copy or copies of the required information at costs of reproduction not to exceed 10 cents per page.

The Commission has exempted the United States Fish and Wildlife Service, the National Marine Fisheries Service, and the state agency responsible for fish and wildlife resources from the requirement of reimbursing the existing licensee for the costs of reproducing the required information. The existing licensee must promptly make requested copies available to those agencies without charge because of their important statutory role under the Fish and Wildlife Coordination Act and the procedural requirements of ECPA.

Effective Date: This Interim Rule became effective 30 days after publication in the Federal Register (April 7, 1987).

Industry Perspective of Interim Rule: This Interim Rule became effective without prior notice or comment. The Commission found good cause that it was "impractical," "unnecessary," or "contrary to public interest" for a notice and comment period under the APA. Specifically, the Commission found it "impractical" for notice and comment because Congress required the Commission to issue the Rule within 180 days following enactment of ECPA, and a notice and comment period would have unavoidably prevented the Commission from executing its agency functions in implementing the rule. General industry comments have not been received.

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Docket No. RM 87-8-000: Amends regulations governing applicants for hydroelectric licenses and exemptions that seek benefits under Section 210 of Public Utilities Regulatory Policies Act for projects to be located at a new dam or diversion.

Summary: Section 8(a) of ECPA amended Section 210 of PURPA to create a new Section 210(j) which imposes three new environmental requirements before applicants for licenses or exemptions can obtain PURPA benefits for small hydroelectric facilities utilizing new dams or diversions.

Section 8(e) of ECPA imposes a moratorium of approximately two years on the grant of PURPA benefits to projects at new dams or diversions while Congress, with the assistance of the Commission, studies the matter.

Section 8(b) of ECPA provides four (4) categories of exceptions from the new requirements in Section 8(a) and moratorium in Section 8(e).

Background

Section 210 of PURPA requires electric utilities to sell electricity to, and purchase electricity from, qualifying small power production facilities.

Section 8 of ECPA also amends Section 210 of PURPA to add a new Section 210(j) which imposes three environmental conditions that license and exemption applicants for hydroelectric projects located at a new dam or diversion will have to meet to qualify for PURPA benefits. The three new conditions of Section 8(a) are:

1. At the time of issuance of the license or exemption for the project, the Commission must find that the project will not have substantial adverse effects on the environment, including recreation and water quality ("adverse environmental effects requirement");

2. At the time the application for a license or exemption for the project is accepted by the Commission, such project cannot be located on any segment of a natural watercourse which:

   a. is included in, or designated for potential inclusion in, a state or national wild and scenic river system, or

   b. the State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural, or scenic attributes which would be adversely affected by hydroelectric development

   ("protected rivers requirements");

3. The project must meet the terms and conditions set by fish and wildlife agencies under the same procedures as provided for under Section 30(c) of the FPA.

In Section 8(e) of ECPA, Congress imposed a moratorium of approximately two years on the availability of PURPA benefits to hydroelectric projects located at a new dam or diversion. The purpose of the moratorium is to allow Congress time to evaluate whether PURPA benefits should continue to be extended to small hydroelectric projects that create new dams or diversions of water.

In order to develop a factual record concerning the impact of extending PURPA benefits to hydroelectric projects located at a new dam or diversion, Section 8(d) of ECPA requires the Commission to conduct a study to be submitted to Congress to determine whether PURPA benefits should be available to these projects. The moratorium will end at the expiration of the first full session of Congress following the session during which the Commission reports to Congress on the results of the study.

Congress recognized the potential hardship these new requirements could impose on developers that were well on the way to obtaining regulatory approval of their projects at the time ECPA was enacted. As a result, Section 8 of ECPA excepts four classes of projects from one or more of the new requirements for PURPA benefits in order to alleviate potential hardship to developers that, relying on existing law, had expended substantial funds and effort in preparing license or exemption applications for projects located at a new dam or diversion with the expectation that these projects would receive PURPA benefits. Any applicant excepted from one or more of the new requirements for PURPA benefits also will be expected from the moratorium. These exceptions are as follows:

1. None of the three requirements applies if the project is located at a government dam at which non-federal hydroelectric development is permissible.

2. None of the three requirements applies if the application was filed and accepted for filing by the Commission before October 16, 1986.

3. Only the protected rivers requirement applies if the application was filed before October 16, 1986, and accepted for filing by the Commission between October 16, 1986, and October 16, 1989.

4. The fish and wildlife agency conditions requirement will not apply to an applicant whose application was filed on or after October 16, 1986, if the Commission finds that, before October 16, 1986, the applicant committed substantial monetary resources to the development of the project and to the diligent and timely completion of all filing requirements of the Commission.

The first three exceptions are self-implementing, while the fourth is only available if the Commission affirmatively grants the exception upon application, in the form of a petition. The statute requires that a petition seeking an exception from the fish and wildlife agency condition requirement (because the applicant had already committed substantial resources) must be filed within 18 months after the enactment of ECPA (that is, by April 16, 1988).

Section 8(b)(4)(C) of ECPA provides that an applicant for license or exemption that files a commitment of resources petition may, prior to the time the license or exemption is issued, file a second petition requesting an initial determination from the Commission on whether the project satisfies the requirement against adverse environmental effects. If an applicant's commitment of resources petition is granted, the Commission will make an initial determination on the adverse environmental effects petition. Section 8 further provides that, if the Commission initially determines that the project as proposed would not satisfy the adverse environmental effects requirement, then the applicant will be provided a reasonable opportunity to propose measures to mitigate the adverse environmental effects found before the Commission finally acts on the license or exemption application and makes a final determination on whether the adverse environmental requirements have been met.

Overview: The Commission is merely implementing the requirements of ECPA by amending its current regulations to incorporate the three additional requirements for projects qualifying for PURPA benefits at new dams or diversions. These projects will not qualify for PURPA benefits during the moratorium period. However, certain of these projects, excepted by the moratorium, may qualify if they meet or are excepted from each of the three new environmental requirements.

The regulatory text of the first three exceptions merely tracks the terms of Section 8 of ECPA. The Commission is excepting from the moratorium and from all three new requirements any project located at a government dam where non-federal hydroelectric development is permitted, and any project for which an application for license or exemption was filed and accepted before October 16, 1986. The Commission is also excepting from the moratorium, the adverse environmental effects requirement, and the fish and wildlife conditions requirement, but not from the protected rivers requirement, any project for which an application for license or exemption was filed before October 16, 1986, and is accepted by the Commission before October 16, 1989.

The fourth exception applies to a project for which an applicant demonstrates, in a petition filed with the Commission, that a substantial commitment of monetary resources was made prior to the enactment of ECPA. The project will be excepted from the moratorium and from the fish and wildlife agency conditions requirement, but not from the adverse environmental effects requirement or the protected rivers requirement. The regulations provide standards and procedures governing petitions claiming a substantial monetary commitment.

Effective Date: Notice and comment procedures were not provided in this Interim Rule. The Commission determined this Interim Rule would not have significant impact on small entities, thus provision of regulatory flexibility acts does not apply. Further, the Commission determined that this rule falls under the APA and thus notice and comment before issuance of a Final Rule is impractical or unnecessary, although comments would be considered. Congress mandated the issuance of a rule within 120 days following enactment of ECPA, thus time for notice and comment was unavailable.

The effective date of the Interim Rule is 30 days after publication in the Federal Register (February 20, 1987).

Industry Perspective of Interim Rule: As with other rules which fall under Congressional mandate or are excluded from notice and comment periods, no public comments were filed on the Interim Rule.

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NOTICE OF PROPOSED RULEMAKINGS

Docket No. RM-87-13-000: Amends the regulations governing applicants for hydroelectric licenses and exemptions, for projects located at a new dam or diversion, that seeks benefits under Section 210 of PURPA.

Summary: In this proposed rulemaking, the Commission requires every application for license or exemption for a hydroelectric project with a power capacity of 80 MW or less to state whether PURPA benefits will be sought and, if so, whether the project will be located at a new dam or diversion. In addition, the Commission is proposing to establish procedures for the filing and processing of a petition pursuant to Section 8(b)(4)(C) of ECPA.

Background: The FPA defines "small power production facility" to include facilities with a power production capacity of 80 megawatts or less that produce electric energy solely by the use of renewable resources. The Commission has interpreted "renewable resources" to include water used at hydroelectric projects located at either an existing dam or a new dam or diversion. Therefore, small hydroelectric projects qualify for, or may seek, PURPA benefits. Docket No. RM 87-8-000 (presented previously) more fully describes the three new requirements for a project to qualify for PURPA benefits. It also describes the moratorium and the four exceptions to the moratorium.

Section 8(b)(4) sets forth a series of specific steps that a qualifying applicant must take in order to satisfy, or be excepted from, the fish and wildlife agency requirement and the adverse environmental effects requirement in Section 210(j) of PURPA. An applicant would qualify for Section 8(b)(4) if its application was filed on or after October 16, 1986, and if the Commission finds that before October 16, 1986, the applicant committed substantial monetary resources to the development of the project and to the diligent and timely completion of all the filing requirements of the Commission. The applicant must file a "commitment of resources petition" which demonstrates the commitment of substantial monetary resources prior to the enactment of ECPA. If the commitment of resources petition is denied by the Commission, all the new requirements in Section 210(j) of PURPA apply, and the applicant is not exempted from the moratorium. If the commitment of resources petition is granted, the applicant is excepted from the fish and wildlife agency requirement in Section 210(j)(3) of PURPA. In addition, the applicant may file a second petition and receive a preliminary determination whether the project satisfies the adverse environmental effects requirement in Section 210(j)(1) of PURPA. It is this second petition, the Adverse Environmental Effects (AEE) petition, that is the subject of this notice. By filing an AEE petition the applicant, who is already excepted from the fish and wildlife agency requirement, would receive a preliminary determination from the Commission on whether the project satisfies the adverse environmental effects requirement. If, on the basis of the AEE petition, the Commission initially decides that the project will have a substantial adverse effect, it must give the applicant a reasonable opportunity to provide for mitigation of such adverse effects before making a final determination. If the Commission initially decides that the project will not have a substantial adverse effect, it will afford interested state(s) a reasonable opportunity to make any determinations under the protected rivers requirement before making a final determination. The Commission is proposing to notify the appropriate federal and state agencies of its initial finding. The Commission must make a final determination on the AEE petition at the time the license or exemption is issued. If a state has not taken any action before the Commission makes it final determination, the failure to take such action gives rise to a presumption that the project has no substantial adverse effect on the environment for those environmental attributes listed in Section 210(j)(2) of PURPA.

Overview: Prior to ECPA there was no distinction for obtaining PURPA benefits between new dams and diversions, and existing dams. ECPA introduces this distinction, imposing three new environmental requirements on projects located at new dams or diversions. Applicants may not always be able to determine if their project is a new dam or diversion or is reconstruction at an existing dam. If an applicant makes an incorrect determination of a project's status, regardless of whether the mistake was inadvertent or deliberate, the applicant could avoid the requirements of Section 210(j) of PURPA. Therefore, in order to comply with ECPA, the Commission must verify whether or not the project is located at a new dam or diversion.

Specifically, requiring an applicant with a hydroelectric project with a power capacity of 80 megawatts or less to state in its application whether or not it will seek PURPA benefits will allow the Commission to determine which projects require verification. If, prior to the issuance of a license or exemption, an applicant files a statement reversing its intent not to seek PURPA benefits, the Commission proposes to treat the statement as an amendment to the application which materially amends the proposed plans of development. This would encourage an applicant, at the outset, to decide whether to seek PURPA benefits. Treating a reversal of intent in this manner would also change the acceptance date of the application to the date on which the amendment was filed. The Commission would then consider the amended application a new filing for the following purposes:

1. Reissuing public notice of the application.

2. Timeliness.

3. Disposal of competing applications.

The Commission also would rescind any acceptance letter for the application if it had issued one. As a consequence, the applicant would be subject to a new notice period and might lose priority among competing applicants.

The Commission is proposing to prohibit an applicant who reverses its intent not to seek PURPA benefits after a license or exemption has been issued from obtaining PURPA benefits. This proposal would prevent an applicant from deliberately avoiding the requirements in Section 210(j) of PURPA by initially stating its intention not to seek PURPA benefits and then, after the license or exemption had been issued, attempting to seek PURPA benefits as a project at an "existing dam."

If an applicant states its intent to seek PURPA benefits but is not successful, the Commission will have specifically considered the issue of PURPA benefits and will have an adequate record. Therefore, if circumstances were to change, and the applicant could demonstrate that the changed circumstances negated the Commission's reasons for initially denying PURPA benefits, it might qualify for PURPA benefits.

The Commission is proposing standards and procedures for filing an AEE petition.

If the Commission has granted the commitment of substantial monetary resources petition, and the applicant has filed an AEE petition, the Commission will make an initial determination whether the project will satisfy the adverse environmental effects requirement in Section 210(j)(1) of PURPA. Therefore, the AEE petition should simply identify the project and request that the Commission make an initial determination on the Adverse Environmental Effects requirement. The Commission will make a final determination on the AEE petition at the time it issues the license or grants the exemption. If the appropriate state(s) has not taken any action before the Commission makes a final determination, a presumption arises that there are no substantial adverse effects. The state must act before the Commission makes a final determination on the AEE petition (i.e., when the Commission issues the license or grants the exemption) to prevent the presumption from arising.

The Commission anticipates that the state will be well aware of all projects subject to Section 8(b)(4) of ECPA and will have ample opportunity to comment on the initial determination. First, the Commission will notify the state when it issues an initial determination on the AEE petition. Second, before any application for a license or exemption can be submitted to the Commission, applicants must complete the requisite prefiling consultation requirements. These requirements include consultation with state agencies. Therefore, since a state is given ample notice under these circumstances, it is reasonable to presume that the state's inaction indicates that the state does not object to the project.

Although the Commission would make the final determination on the AEE petition when it issues the license or grants the exemption, the Commission proposes to delegate to the Director of the Office of Hydropower Licensing (Director) the authority to make an initial determination on the AEE petition. The Director would make an initial finding on the petition after the close of the public notice period. The Director would also provide written notice of this finding to the applicant and to the appropriate federal and state agencies.

Comment Period: The Commission requested persons to submit written data, etc., until 30 days after the NOPR was published in the Federal Register (October 16, 1987). The filing period ended on November 16, 1987.

Industry Perspective of NOPR: Though specific industry comments are undetermined relating to this specific NOPR, the industry strongly supports the continuation of incentives provided by PURPA for hydroelectric facilities at new dams and diversions.

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Docket No. RM 87-24-000: Procedures for assessment of civil penalties under Section 31 of the FPA.

Summary: Section 12 of ECPA amended the FPA by adding a new Section 31. This section, in general, authorizes the Commission to assess civil penalties. The section supplements the Commission's existing authority relating to issuance of compliance orders or to take other remedial actions.

Background: The new Section 31 of the FPA has four subsections.

Subsection (a) affirms the Commission's authority to monitor and investigate compliance with licenses, permits, and exemptions issued for hydroelectric projects. This subsection also sets forth the Commission's authority to issue certain compliance orders which, if violated, provide a basis for enforcement action under subsections (b) or (c).

Section 31(a) of the FPA states: Monitoring and Investigation - The Commission shall monitor and investigate compliance with each license and permit issued under this Part and with each exemption granted from any requirement of this Part. The Commission shall conduct such investigations as may be necessary and proper in accordance with this Act. After notice and opportunity for public hearing, the Commission may issue such orders as necessary to require compliance with the terms and conditions of licenses and permits issued under this Part and with the terms and conditions of exemptions granted from any requirement of this Part.

Subsection (b) states the conditions under which the Commission may issue an order revoking a license or exemption.

Section 31(b) of the FPA states: Revocation Orders - After notice and opportunity for an evidentiary hearing, the Commission may also issue an order revoking any license issued under this Part or any exemption granted from any requirement of this Part where any licensee or exemptee is found by the Commission:

1. to have knowingly violated a final order issued under subsection (a) after completion of judicial review (or the opportunity for judicial review); and

2. to have been given reasonable time to comply fully with such order prior to commencing any revocation proceeding.

In any such proceeding, the order issued under subsection (a) shall be subject to de novo review by the Commission. No order shall be issued under this subsection until after the Commission has taken into consideration the nature and seriousness of the violation and the efforts of the licensee to remedy the violation.

Subsection (c) sets forth the persons subject to a civil penalty, the conduct which may subject those persons to a civil penalty, and factors which the Commission must take into account in determining the amount of a proposed penalty.

Section 31(c) of the FPA states: Civil Penalty - Any licensee, permittee, or exemptee who violates or fails or refuses to comply with any rule or regulation under this Part, any term, or condition of a license, permit, or exemption under this Part, or any order issued under subsection (a) shall be subject to a civil penalty in an amount not to exceed $10,000 for each day that such violation or failure or refusal continues. Such penalty shall be assessed by the Commission after notice and opportunity for public hearing. In determining the amount of a proposed penalty, the Commission shall take into consideration the nature and seriousness of the violation, failure, or refusal and the efforts of the licensee to remedy the violation, failure, or refusal in a timely manner. No civil penalty shall be assessed where revocation is ordered.

Subsection (c) also provides that no civil penalty shall be assessed where revocation is ordered. Subsection (d) establishes alternative civil penalty assessment procedures.

Section 31(d) of the FPA states: Assessment:

1. Before issuing an order assessing a civil penalty against any person under this section, the Commission shall provide to such person notice of the proposed penalty. Such notice shall, except in the case of a violation of a final order issued under subsection (a), inform such person of his opportunity to elect in writing within 30 days after the date of receipt of such notice to have the procedures of paragraph (3) (in lieu of those of paragraph (2)) apply with respect to such assessment.

2.a In the case of the violation of a final order issued under subsection (a), or unless an election is made within 30 calendar days after receipt of notice under paragraph (1) to have paragraph (3) apply with respect to such penalty, the Commission shall assess the penalty, by order, after a determination of violation has been made on the record after an opportunity for an agency hearing pursuant to Section 554 of Title 5, United States Code, before an administrative law judge appointed under Section 3105 of such Title 5. Such assessment order shall include the administrative law judge's findings and the basis for such assessment.

2.b Any person against whom a penalty is assessed under this paragraph may, within 60 calendar days after the date of the order of the Commission assessing such penalty, institute an action in the United States Court of Appeals for the appropriate judicial circuit for judicial review of such order in accordance with Chapter 7 of Title 5, United States Code. The court shall have jurisdiction to enter a judgment affirming, modifying, or setting aside in whole or in part, the order of the Commission, or the court may remand the proceeding of the Commission for such further action as the court may direct.

3.a In the case of any civil penalty with respect to which the procedures of this paragraph have been elected, the Commission shall promptly assess such penalty, by order, after the date of the receipt of the notice under paragraph (1) of the proposed penalty.

3.b If the civil penalty has not been paid within 60 calendar days after the assessment order has been made under subparagraph (a), the Commission shall institute an action in the appropriate district court of the United States for an order affirming the assessment of the civil penalty. The court shall have authority to review de novo the law and the facts involved, and shall have jurisdiction to enter a judgment enforcing, modifying, and enforcing as so modified, or setting aside in whole or in part, such assessment.

3.c Any election to have this paragraph apply may not be revoked except with the consent of the Commission.

4. The Commission may compromise, modify, or remit, with or without conditions, any civil penalty which may be imposed under this subsection, taking into consideration the nature and seriousness of the violation and the efforts of the licensee to remedy the violation in a timely manner at any time prior to a final decision by the court of appeals under paragraph (2) or by the district court under paragraph (3).

5. If any person fails to pay an assessment of a civil penalty after it has become a final and unappealable order under paragraph (2), or after the appropriate district court has entered final judgment in favor of the Commission under paragraph (3), the Commission shall institute an action to recover the amount of such penalty in any appropriate district court of the United States. In such action, the validity and appropriateness of such final assessment order or judgment shall not be subject to review.

6.a Notwithstanding the provisions of Title 28, United States Code, or of this Act, the Commission may be represented by the general counsel of the Commission (or any attorney or attorneys within the Commission designated by the Chairman) who shall supervise, conduct, and argue any civil litigation to which paragraph (3) of this subsection applies (including any related collection action under paragraph (5)) in a court of the United States or in any other court, except the Supreme Court. However, the Commission or the general counsel shall consult with the Attorney General concerning such litigation, and the Attorney General shall provide, on request, such assistance in the conduct of such litigation as may be appropriate.

6.b The Commission shall be represented by the Attorney General, or the Solicitor General, as appropriate, in actions under this subsection, except to the extent provided in subparagraph (a) of this paragraph.

The civil penalty provisions enacted in those subsections may be summarized as follows:

Licensees, permittees, and exemptees are subject to civil penalties of up to $10,000 per day for each violation of, or failure or refusal to comply with, any rule or regulation issued under Part I of the FPA, any term or condition of a license, permit, or exemption issued under Part I of the FPA, or a compliance order issued under subsection (a)(1). The amount of the proposed penalty must reflect the nature and seriousness of the violation and the timely remedial efforts of the person against whom the penalty is proposed. No penalty may be assessed where a license or exemption is revoked.

Overview:

Section 385.1501 of the proposed rules provides that the rules apply to proceedings to assess civil penalties pursuant to Section 31 of the FPA.

Section 385.1502 states that any licensee or permittee under the FPA, and any exemptee from any requirement of Part I of the FPA, may be subject to civil penalties.

Section 385.1503 of the proposed rules sets forth the actions that would subject persons to civil penalties. Those actions are violations of, or failures or refusals to comply with: (1) any rule or regulation issued under Part I of the FPA; (2) any term or condition of a license, permit, or exemption; or (3) any order issued pursuant to Section 31(a) of the FPA to require compliance with terms and conditions of licenses, permits, or exemptions issued under Part I of the FPA.

Under Section 31(c) of the FPA, the Commission may not assess a civil penalty of more than $10,000 for each day that such violation or failure or refusal continues, and no civil penalty may be assessed where a license or exemption is ordered revoked. Section 385.1504 of the proposed rules reflects these limitations.

In determining the amount of a proposed penalty, Section 31(c) of the FPA requires the Commission to consider (1) the nature and seriousness of the violation, failure, or refusal, and (2) the efforts of the licensee to remedy the violation, failure, or refusal in a timely manner.

In considering the "nature" of the violation, the Commission proposes to consider the violator's compliance history, and whether the violator had actual knowledge or the constructive knowledge deemed to be possessed by a reasonable individual acting under similar circumstances. Other factors being equal, a knowing violation will subject a person to a higher civil penalty than a violation which is not knowing.

In considering the "seriousness" of the violation, the Commission proposes to consider whether the violation resulted in loss of life, whether and to what extent persons were injured or property or the environment was damaged, and whether persons, property, or the environment were endangered but not damaged.

In considering the remedial efforts of the violator, the Commission proposes to consider whether the violator remedied the violation in a timely manner, in an untimely manner, or failed to remedy the violation. A violation followed by untimely remedial efforts will subject a person to a higher civil penalty than a violation followed by timely remedial efforts, other factors being equal.

FPA Section 31 does not require the Commission to publish criteria for calculating the dollar amount at which to propose or assess a penalty, and it has been historically rare for federal agencies in general to publish such criteria.

FPA Section 31(d)(1) requires the Commission to provide notice of the proposed penalty to the person against whom the penalty is to be assessed. The new Section 385.1506(a) embodies this requirement.

Where there is a right to an election, the Commission must inform the person against whom the penalty is to be assessed of that person's opportunity to elect the procedures to be followed; i.e., the administrative evidentiary hearing of FPA Section 31(d)(2) or the United States District Court procedures of FPA Section 31(d)(3).

Under Section 31(d)(1) of the FPA, a person to whom a notice of proposed penalty is issued has thirty days from receipt of such notice to elect in writing between the procedures of FPA Section 31(d)(2) and Section 31(d)(3).

The administrative hearing procedures of FPA Section 31(d)(2) automatically apply unless the person has the right to an election and exercises that right within 30 days of receipt of the notice of proposed penalty.

The Commission proposes to treat as "final," compliance orders issued by staff pursuant to delegated authority and from which no appeal has been filed.

FPA Section 31(d)(3)(C) provides that a person may revoke an election to require FPA Section 31(d)(3) District Court procedures only with the consent of the Commission.

There are four phases to the assessment process under FPA Section 31(d)(2).

1. In the first phase, the Commission would provide an opportunity for a hearing before an Administrative Law Judge (ALJ) and would utilize, as appropriate, the hearing procedures set forth in 18 C.F.R. Part 385, Subpart E (1986).

2. In the second phase, the Commission would issue an assessment order which would include the ALJ's initial decision, if any, and the Commission's basis for the assessment.

3. In the third phase, the person against whom the penalty is assessed could appeal to an appropriate United States Court of Appeals within 60 calendar days after the date of the order of the Commission assessing such penalty.

4. In the fourth phase, the Court of Appeals may affirm, modify, set aside in whole or in part, or remand the matter to the Commission.

There are two phases to the assessment process under FPA Section 31(d)(3) procedures.

1. In the first phase, FPA Section 31(d)(3)(A) provides that the Commission shall promptly assess the penalty, by order, after the notice of election is received by the Commission.

2. In the second phase, if the penalty has not been paid within 60 days of the date of issuance of the assessment order, the Commission shall institute an action in United States District Court for an order affirming the civil penalty.

Section 31(d)(4) of the FPA gives the Commission the authority to compromise, modify, or remit, with or without conditions, any civil penalty. However, the GAO has recently released a report dated March 4, 1988, addressed to the Honorable John Dingel, Chairman of the Subcommittee on Oversight and Investigations of the Committee on Energy and Commerce, which recommends "... that the Commission take steps to ensure timely and consistent follow-up on overdue compliance items, improve the accuracy of its computerized tracking system to make it more useful as a monitoring tool, and ensure that a comprehensive compliance history is developed on a project when it is needed for relicensing or enforcement purposes."

As provided in Section 31(d)(5) of the FPA, the rules propose that the Commission institute an action to recover an unpaid civil penalty in an appropriate United States District Court.

Comment Period: The Commission requested interested persons to submit written comments, data, etc., until 60 days after the NOPR was published in the Federal Register (August 6, 1987). The filing period ended on October 5, 1987.

Industry Perspective of NOPR: The enforcement authorities granted to the Commission by Section 31 were intended to promote compliance with regulatory requirements, not simply to punish malefactors. With compliance as the goal, the Commission should adopt the use of compliance orders as the means for addressing violations for failure to comply with regulatory requirements and, only after a failure to respond to the compliance order, impose civil penalties.

The Commission should retract its attempt to expand the meaning of Section 31 in the Final Rule. Alternatively, the Final Rule should provide that in cases which the only alleged violation involves operation of a project without authority under Part I, civil penalties are only available after an order asserting jurisdiction has become final, and non-appealable, and only then after the project owner fails to apply for a license for exemption within such reasonable period of time as the Commission may establish.

The industry does not suggest that the owners of small or single-asset projects be excused from civil penalty assessments. It is believed, however, that the Commission may, and indeed should, vary the amounts of civil penalties depending on the target of the assessment, even where the alleged violation is identical. One purpose of a civil penalty assessment should be to deter future violations by the licensee or exemptee; a relatively modest civil penalty assessment for the small project operator will be just as meaningful in governing that person's future conduct as a massive civil penalty against a large business organization. All licensees and exemptees are not created equal in their ability to pay civil penalties, and the Commission's rule 1505 should so acknowledge.

The industry believes that the Commission should approach its civil penalty program on an incremental basis. Rather than imposing large penalties up front, NHA suggested that the Commission impose relatively modest penalties to begin with, that it publicize its assessment of those penalties to the maximum possible extent, and make clear that future violators will be dealt with more firmly, in terms of civil penalty amounts, than the earlier violators. This graduated approach to compliance should serve to avoid the temptations inherent in the "make an example of" approach; will avoid the distortion of precedent, in terms of dollar amounts, inherent in such an approach; and will serve to put the industry on notice that as time goes on, and both the Commission and the regulated industry gain experience under the program, the Commission will approach violations with less and less leniency.

* * * * *

Docket No. RM 87-33-000: Proposed rule to revise Commission regulations governing the relicensing of hydroelectric power projects.

Summary: Congress amended the FPA to establish new procedures and standards for the relicensing of a hydroelectric power project subject to Sections 14 and 15 of the FPA. ECPA mandated that the Commission consider additional factors in granting a new license (relicense). ECPA clarified that a municipality is not entitled to preference in relicensing. ECPA also established new procedural requirements for a new license.

Background: To conform to the requirements of ECPA, the Commission issued this NOPR which proposes revisions to its regulations concerning relicensing of hydroelectric power projects. Proposed changes include:

1. Revised requirements for an application for a new license.

2. Prefiling consultation process with resource agencies.

3. New standards and factors for evaluating relicense applications.

4. Revisions to procedures for an application for a non-power license, minor license, exemption from licensing.

5. Provisions for acceleration of a license expiration date.

6. Site access for potential competing applicant.

7. Miscellaneous editorial changes for takeover of a project by U.S.

Overview: Summarized below are the more specific components of the modifications to preparing a relicense application.

1. Requirements for application for a new license.

   ECPA amended the FPA to require that an applicant for a new license file its application at least 24 months before the expiration of the existing license. The Commission proposes to require that an applicant must file an application for a new license at least 24, but not more than 30 months, before the expiration of a license. The Commission's office of Hydropower Licensing (OHL) would review an application for a new license, identify deficiencies, and notify the applicant of any deficiencies within 90 days of the filing of the application. The Commission proposes that an applicant be required to correct deficiencies and make any final amendments in its application by 18 months before the expiration date of the existing license. The Commission proposes that an application for a new license will be processed in accordance with existing regulations governing the contents and adequacy of an application for an initial license.

The status of an applicant as an existing licensee in filing for a new license is relevant because the FPA, as amended by ECPA, provides that insignificant differences among applications with regard to the factors enumerated in Section 15(a)(2)(A) through (G) should not result in the transfer of a license for a project from an existing licensee. The regulations proposed in this NOPR would impose somewhat different obligations for providing information on applicants for a new license, based on whether or not an applicant is the existing licensee of the project.

The Commission also proposes that an existing licensee that has filed a negative notice of intent may not subsequently file an application for a new license for the project. The Commission proposes this provision to prevent potential non-licensee applicants who may otherwise expend resources in preparing an application in the belief that the existing licensee is not seeking a new license from being misled. The Commission proposes that an applicant that does not file an application by 24 months before the expiration of an existing license would be barred from consideration as an applicant for that project. If the existing licensee stated in its notice of intent that it would file an application and there is no pending application for a new license 24 months before the expiration date of the license, the Commission proposes to issue a public notice soliciting notices of intent to file an application for a license from potential applicants other than the existing licensee.

In the situation in which no notice of intent is filed or no subsequent license application is filed, the proposed regulatory text requires an existing licensee to file an application for surrender of the project. However, the Commission proposes to offer an existing licensee one last opportunity to choose between applying to surrender the project and applying for a license to continue to operate the project, but determination of the appropriate procedural framework for such applications poses a problem. The Commission proposes to treat an existing licensee applying at this stage as an existing licensee seeking a relicense in order to apply the relicense standards and procedures set out in this NOPR. However, the two-year statutory deadline for filing a relicense application appears to preclude that approach. In this case, it may be necessary for an existing licensee to file a notice of intent under Section 4(e) of the FPA, which applies to the initial license process.

The Commission also proposes certain procedural regulations relating to the filing of an application for a new license.

2. Prefiling consultation with resource agencies.

Under current Commission regulations, an applicant must consult with each appropriate federal and state agency prior to filing its application to determine what studies should be conducted and what mitigation measures should be undertaken. An applicant generally meets with the agencies individually. At times, an applicant has been faced with conflicting requests from different agencies. Since the applicant may meet with each agency separately, the applicant may be unaware of the differences among the agencies until it is well along in the consultation process. The applicant may then seek to resolve the conflicting requests, again by meeting with each agency individually. The resolution process may require several rounds of meetings with each agency before the applicant has accommodated and reconciled the concerns of each federal and state agency. The Commission proposes to improve the consultation process by allowing that an applicant participate in a joint consultation process with the relevant federal and state agencies. The joint consultation process would consist of three stages: (1) the initial review of the existing project and any proposed changes and the determination of necessary studies; (2) completion of the studies requested during the first stage, determination of appropriate mitigation measures, and preparation and review of a draft application; and (3) receipt of a final application, incorporating information generated during the first two stage of consultation.

The applicant and the resource agencies would participate in a series of joint meetings during the first stage of consultation to ensure that all agencies understand the proposed project and to determine what studies should be performed. During the second stage of consultation, studies would be conducted and, if necessary, a series of joint meetings would be held between the applicant and the resource agencies to agree on environmental mitigation and enhancement measures.

The Commission proposes to specify that a period of 30 days after a joint meeting or conference call is a reasonable time within which an agency must identify needed studies under the first stage of consultation. The Commission encourages resource agencies to be consistent in determining the necessary studies and mitigation measures for all similar proposals at a site.

If an agency did not participate in a joint meeting or conference call or failed to respond in a timely manner to an applicant's request for consultation, the Commission would deem that agency to have waived compliance with consultation requirements. Thus, if an applicant does not receive a decision from an agency concerning the need for a study or the type of study to be conducted within 30 days after a joint meeting or conference call, the applicant may proceed to conduct a study that it believes is appropriate for the Commission to analyze the merits of the project.

When a resource agency and an applicant are unable to agree on whether a study is required or on the type of study to be conducted, the applicant may refer the matter to the Director of OHL for resolution.

3. Standards and factors in relicense determination.

ECPA amended the FPA to make clear that municipal preference did not apply to new licenses, with the intent of creating an atmosphere of open and equal competition to facilitate optimum development of relicensed projects. The statute does provide that "insignificant differences" by competing applications will not result in a transfer of license. To make the determination in these "close calls," the NOPR specifies standards and factors in the evaluation process. If there are only insignificant differences between the final proposals of an existing licensee and a competing applicant, the Commission proposes to use Section 15(a)(3) as the dispositive factor in awarding the new license.

Factors which will be considered include:

a. The applicant's compliance with existing license terms and conditions and other applicable provisions of Part I of the FPA.

b. The applicant's plan to manage, operate, and maintain the project safely.

c. The applicant's plans and ability to operate and maintain a project in a manner to provide efficient and reliable electric service.

d. The applicant's (1) need for power, for long and short term; (2) consideration of alternative sources of power; (3) effect on providers and recepients of alternative sources of power; (4) load and operating characteristics; and (5) impact on industrial needs and community effects.

e. The applicant's existing and planned transmission system.

f. The applicant's cost-effective manner in preparing the best plan.

g. Other factors which include comprehensive plans, fish and wildlife agency recommendations, etc.

The remaining provisions of the NOPR include procedures for a minor license, procedures for a non-power license, application for exemption, privileged treatment of proprietary information, acceleration of a license expiration date, site access for a competing applicant, and annual license. Each of these provisions is discussed in the NOPR, but is believed to be too specific to individual interests to be re-evaluated in this paper.

Comment Period: The Commission has invited interested persons to submit written comments no later than 90 days following publication of the NOPR in the Federal Register (June 10, 1988). The filing period will end on September 8, 1988.

In the preamble of the proposed rule, the Commission specifically invited comments on several issues on which it expressed an interest in hearing from the public. These include:

1. Joint development proposals: Whether there are circumstances under which an existing licensee should retain the status of an existing licensee in applying for a new license, despite the fact that it has joined other venturers in its applications.

2. Exception to bar on relicense application: Where the existing licensee fails to file a new license application with the two-year deadline, whether the existing licensee may nonetheless file a joint application with another entity.

3. Indian tribal concerns: The proposed rule expresses the Commission's opinion that "the legislative history of ECPA suggests that Indian tribes are to be permitted to participate in the Section 10(j) process to resolve disputes between fish and wildlife agencies, license applicants, and the Commission." The proposed rule requests comment on the most appropriate mechanism to ensure that tribal concerns are fully considered by the Commission in relicensing.

4. Licensee's record: The Commission requests comments on criteria relating to an existing licensee's record of compliance.

Industry Perspective of the NOPR: Since the NOPR was only issued on May 24, 1988, the hydropower industry is in the midst of review and evaluation. The National Hydropower Association released initial comments in the May 27 issue of Hydro Regulatory Report.

The following are some excerpts from that document:

1. Prefiling Consultation Process.

   The proposed rule includes teeth to promote timely participation by agencies in the consultation process. The preamble states: "If an agency did not participate in a joint meeting or conference call or failed to respond in a timely manner to an applicant's request for consultation, the Commission would determine that agency to have waived compliance with consultation requirements." The rule would give the agency 30 days to decide whether a study is necessary, or the type of study to be conducted, after a joint meeting or conference call.

2. Acceleration of License Expiration Dates.

   It may be that only licensees with ten or more years remaining on their license will find the acceleration termination date mechanism useful.

3. Joint Development Proposals for relicensing.

   The Commission does not state the significance of its tentative position; presumably, for example, if joint development proposals do not represent an "original licensee," then perhaps even insignificant differences could be determinative in a competitive proceeding. The preamble, however, "solicits comments on whether there are circumstances under which an existing license should retain the status of an existing licensee to apply for a new license, despite the fact that it has joined with other venturers in its application."

4. Consequences of existing licensee's failure to file.

   The preamble notes that the Commission solicits comments on whether it should, in this circumstance, give the existing licensee a last opportunity to seek a license, although a new license application would proceed under Section 4(e), rather than under Section 15.

The proposed rule is silent with respect to licensees who fail to make any filing with the Commission at the end of the license term, or with licensees intent on operating a project until the end of the existing license, and then retiring the project from service. In the former case, the Commission might eventually utilize its enforcement powers (including the availability of civil penalties) to require compliance filings, or it may treat the licensee as having implicitly applied for surrender. The latter case, however, is not so clear. A licensee may be within its rights in advising the Commission that, upon expiration of its license, it will retire the project from service. What is not clear is whether the Act requires that the licensee file a surrender application in that circumstance, given that the license will expire of its own terms anyway. Further complicating the picture is the requirement of Section 15 that, if the United States does not take over the project and if the Commission does not issue a new license for a project, it shall issue annual licenses under the same terms and conditions of the original license. These matters will most likely be addressed on a case-by-case basis.

5. Transition provisions.

The only transition provision in the proposed rule provides, somewhat inscrutably, that for applications filed within 90 days from the effective date of the final rule (probably late 1988), the applicant will have an additional 90 days to supplement the application to provide all information required by the final rule. The plain import of this provision is that any existing licensee or competitor commencing work on a new application should proceed according to the proposed rule, and not existing regulations.

The proposed rule does not address two other important categories of project for which some transition provision appears necessary.

a. Pending applications: At least 45, and probably more, relicense applications (and competing applications) are currently pending before the Commission. The proposed rule is silent as to the effect on those cases of the final rule. Particularly important would be whether pending applications will be subject to the "final amendment" provision of ECPA, especially in cases where the Commission's "material amendment" rule would apply. The Commission may intend to address this issue on a case-by-case basis.

b. Applicants in the consultation process: Some applicants are, or soon will be, either engaged in first-stage consultation, or may already have completed first-stage consultation. Those applicants risk being caught between the relatively minimal requirements of existing relicense applications, and those to be required by the final rule.

The above described Final Rules, Interim Rules, and Notice of Proposed Rules have been issued by the Commission since the passage of ECPA in October 1986. Areas where rules have yet to be issued for implementation of ECPA include:

1. Clarifications on equal considerations between power and development purposes and energy conservation, protection, etc., of fish and wildlife, recreation, and other aspects of environmental quality (Section 3 of ECPA affecting Section 4(e) and 10 of FPA).

2. Unauthorized activities outside the scope of the existing license (Section 6 of ECPA affecting Section 23(b) of FPA).

3. Anti-trust laws (Section 13 of ECPA affecting Section 10(h) of FPA).

SUMMARY

To reiterate, this paper identifies the rules and regulations which have been developed and imposed on the hydropower industry in the United States, to date, and also to identify some of the other areas of the FPA where regulations or clarifications of ECPA intent may or will be developed. Further, the purpose of presentation is to create a clearer image of the regulatory process which the United States government, as a developed country, has imposed on the hydropower industry.

With all the regulations currently proposed, or in effect, following enactment of ECPA, only the consultation process in the proposed relicensing rule is designed to minimize the licensee's time and cost. All the remaining requirements will add time and cost to development and administration of a hydropower project, either for new projects or continuation of existing projects.

Specific regulatory policies and procedures have resulted from the Congressional creation of the Electric Consumers Protection Act, which has changed the policy towards hydropower development in the United States by creating a mandatory requirement for giving equal consideration to environmental concerns as well as power production. This is very important, in that, without such balance the integrity of the environment in developed countries may be overlooked at the expense of the natural resources. Other countries throughout the world have a balance between development and environmental concerns, and regulatory action, as resulting from ECPA, may have been taken as "second nature" and without controversy. It is a social acceptance of development.

However, this additional regulatory responsibility provides an opportunity for both the developed country to understand the positions of developing countries and gives the developing countries the opportunity to envision their future as a developed country. The degree of regulatory responsibility which is imposed, on not only the hydropower industry but most development in the United States, is of such a precise, detailed nature that we become overencumbered by the paperwork necessary to satisfy all of the regulatory requirements in order to develop projects and, thus, as we are seeing in the United States at this time, many small entrepreneurs with opportunities for development of small hydropower projects are unable to contend with the regulatory process to develop the projects.

The National Hydropower Association, the industry trade association, has seen a substantial decline in the development of small and large hydropower projects in the United States, and is observing the small hydropower developers transition their efforts into other areas. A balance between the considerations for development for power generation and considerations of environmental aspects that the hydropower development will affect must be maintained harmoniously so as not to deter the development. Though many of the small hydropower producers in the United States were entrepreneurs, they were providing a solution to a problem which exists in the United States. Large power plants, by utilities, are not being developed and, thus, the philosophy of supply and demand may become unbalanced at the time when power demands are greater than power supplies. These factors should be considered by Third World Developing Countries in the early formulation of their policies relating to long-term generation, privatization, utility management, conservation, and legislative actions. It is critical that the examples which have been set forth in the development of the rules and regulations to implement the Electric Consumers Protection Act in the United States, to the ultimate degree of regulation, be considered in the formulation of advancement of our world's energy resources.

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Visual Resource Management for Small Hydropower Development

By
T.C. Camp Jr.

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Visual Resource Management for Small Hydropower Development

Thomas C. Camp, Jr., ASLA

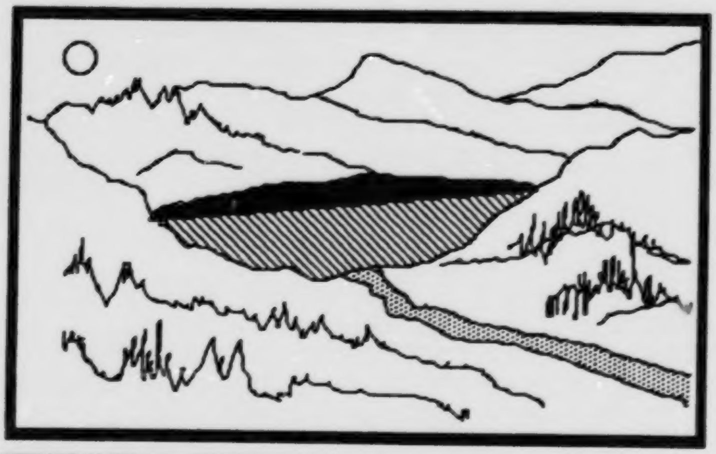
The visual impacts of hydropower development are numerous and varied, often creating contrasting elements in the characteristic landscape. These contrasts can be subtle or dramatic. There is a growing public concern for the manner in which visual resources are managed. Developers and regulatory agencies have an opportunity and an obligation to the public to protect these visual resources. It is important that visual resource management be understood as a public concern and as an opportunity to facilitate high visual quality in hydropower project implementation. This paper is intended as a basic introduction to the subject of visual resource management at hydropower project sites.

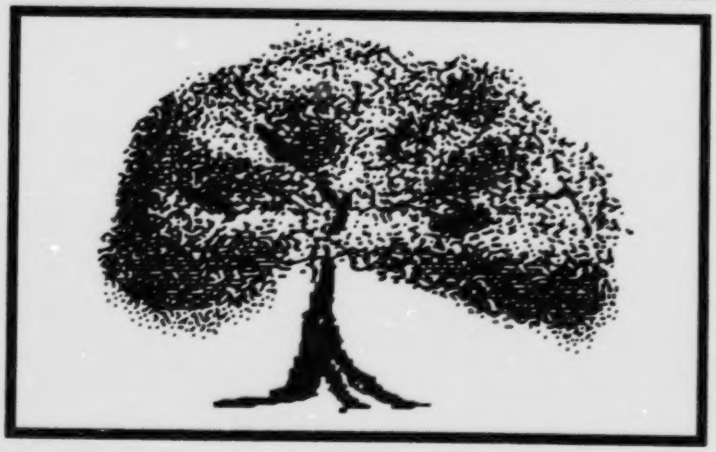
People have a high concern for the quality of the visual environment. They are spending more and more time out-of-doors, either in urban, rural, or natural areas. Much of this leisure time is spent near water. Water is a great magnet for the recreating public. It creates great interest, either as a large body of water extending to the horizon, a large river, a tiny creek that you can step over, a waterfall, or a favorite fishing pond. The point is, water is where people like to go. This attraction to water makes hydropower developments difficult to implement while protecting the visual resources of the project site.

Visual resource management is important to hydropower developers and regulatory and land managing agencies. The public is becoming more aware of the changes that are taking place in their visual environment. This concern is often being expressed in the form of extensive public comments and legal challenges to those agencies or developers seeking to change a favorite landscape by introducing a hydropower facility. The foundations for the expression of the concerns and the legal challenges are established in the National Environmental Policy Act of 1969 (NEPA) as amended, its subsequent implementing regulations, and a host of other laws often relating to specific agencies or situations.

Visual Resource Management

Simply stated, visual resources are those parts of a landscape, rural or urban, which make up what we see. They are the man-made elements, and the natural elements. Each of these elements has a form, line, color, and texture. For example, a large concrete dam has strong three-dimensional form, a horizontal line, a color, and most likely, a smooth texture. A shade tree also has a three-dimensional form, very little line, probably several colors, and a fine or coarse texture, depending upon the species. The various combinations of form, line, color, and texture create the scene we find attractive or unattractive.

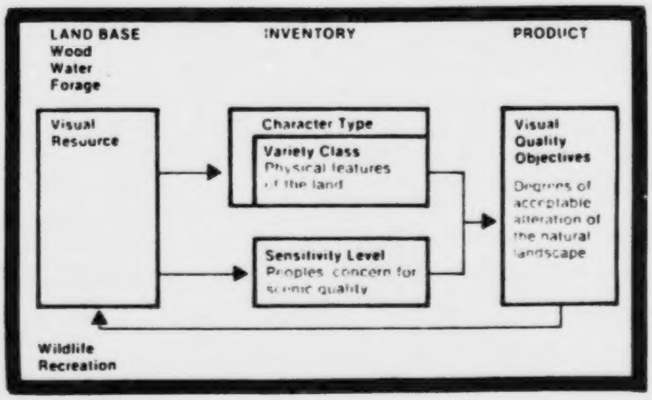




Visual resource management is the planning and design of the visual aspects of any project. The following premises stress the need for management of visual resources in any project design (U.S.D.A. Forest Service 1974):

* expected images exist in the mind of the viewer
* all lands are viewed
* esthetic concern varies and types of viewers are critical
* view duration is critical
* number of viewers is critical
* diverse landscape character is important
* retention of character is important
* the capacity of each landscape to absorb alteration without losing its visual character is critical
* alteration of character may be desired
* viewing distance is critical
* viewing angle is critical
* focus of the viewer is critical
* the visual impact and character of management activities is critical

It is important to follow an systematic analysis process when attempting to describe visual resources and determine their significance. One process which illustrates the relationships of the various steps is shown below (U.S.D.A. Forest Service 1974).


LAND BASE
Wood
Water
Forage
INVENTORY
PRODUCT
Visual Resource
Character Type
Variety Class
Physical features of the land
Sensitivity Level
Peoples concern for scenic quality
Visual Quality Objectives
Degrees of acceptable alteration of the natural landscape
Wildlife
Recreation

An excellent publication for more detailed information on visual management processes is entitled "Foundations for Visual Project Analysis" by Smardon, et.al. An extensive bibliography of visual resource information has been compiled by Ellsworth.

How Hydropower Developments Affect Visual Resources

Small hydropower developments affect visual resources by introducing contrasting elements into a characteristic landscape. The characteristic landscape can be any landscape, from urban to wilderness. Each hydropower development is composed of essentially the same features. With some variation, each has:

Structures:
- *powerhouse
- *dam
- *spillway
- *penstock
- *intake
- *tailrace
- *switchyard/substation
- *transmission line

Other features:
- *borrow areas
- *spoil disposal areas
- *landform modifications
- *access roads, parking lots
- *laydown areas
- *vegetation changes
- *flow changes over dam or spillway or in a bypassed reach

Each of the above facilities or features has the potential to create a change in the visual resources of the site by introducing contrasting forms, lines, colors, and/or textures. The design, location, and construction of each feature will determine the level of public acceptance for the entire hydropower development.

Visual resource management is important at the *planning* stage of hydropower development. This is the time to perform a complete visual resource analysis. This will determine the quality of the existing visual resources, the extent of their importance to those people who are concerned with them, and the public viewpoints. From this analysis, alternative designs and facility locations can be formulated and evaluated. The alternatives can then be documented in the planning records leaving a clear track of how the preferred design was determined.

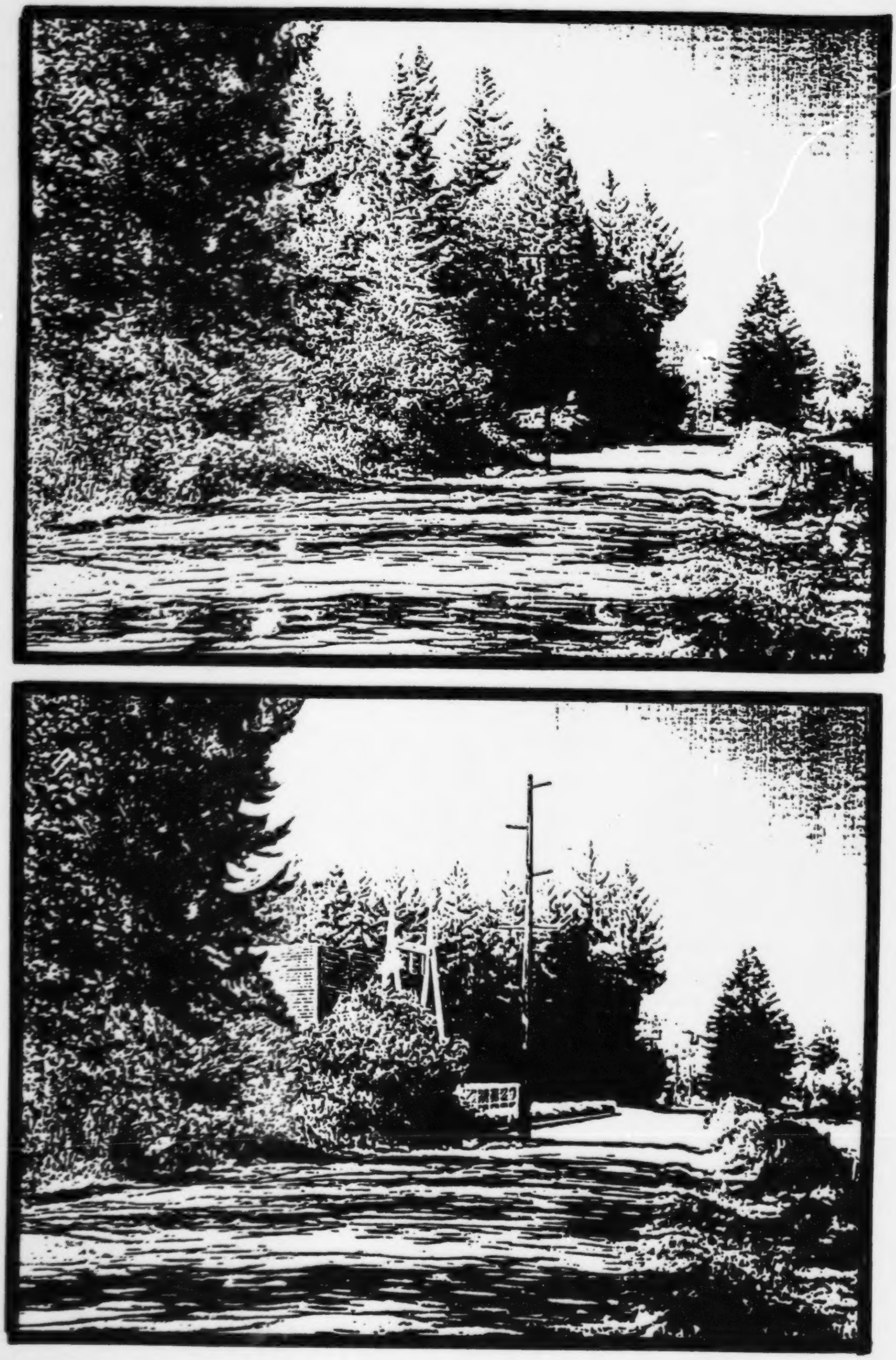
Visual resource management is important at the *construction* stage for this is where the plans are carried out. This is where the project is either made or broken, especially from a visual resource standpoint. The best plans, altered during construction for short-term expediency, implemented poorly or not as designed, may create adverse visual impacts that will last for decades.

Post construction operation is also important. Facilities must be maintained in accordance with the design plans in order to have continued public acceptance of the operating hydropower facility. For example, a structure painted a dark color to reduce its contrast with the surrounding environment may weather to a lighter, reflective color if not repainted periodically.

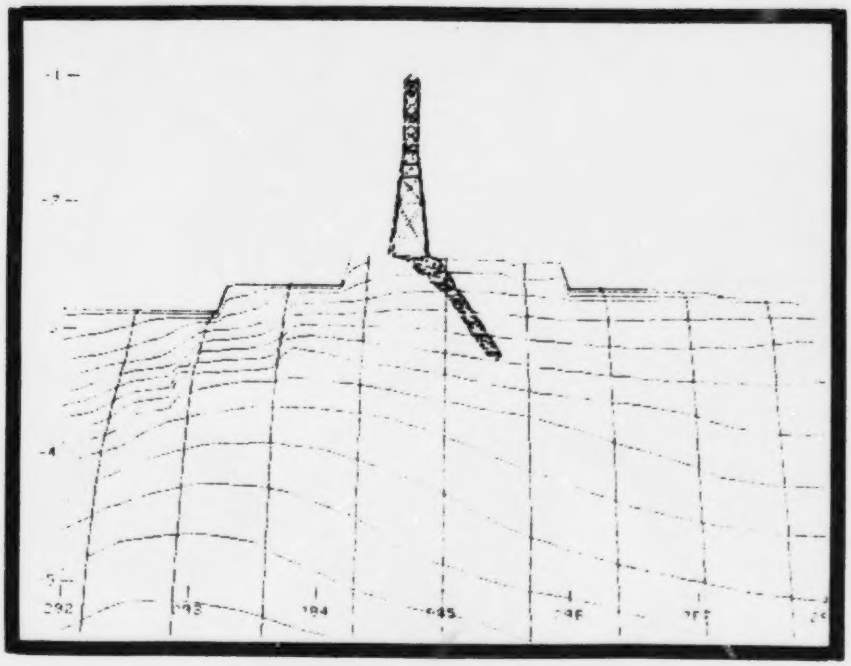
Visual Resource Management Techniques for Impact Reduction

The facility design and location process includes a number of factors which must be considered by hydropower development designers in order to reduce adverse visual impacts. Some of these factors are form, line, color, texture, location, screening, reflectivity, and retention of water flows in bypassed reaches. While a dam may not be a facility easily relocated for reduction of visual impact, the design of most of the other features can benefit from consideration of the above factors. Landform modification features such as borrow and spoil disposal areas, parking lots, and access roads can simulate adjacent natural landforms or can use them as screening from public viewpoints. Linear features such a transmission lines and roads can benefit from an analysis of their contrast with existing landscape features and subsequent placement and design to minimize the contrast. Features may by screened from view through the use of both existing and planned landforms and vegetation. The use of non-contrasting colors, and textured and non-reflective surfaces will also allow a facility to blend with or compliment the characteristic landscape. And maintenance of water flows for a continuation of expected visual quality is important.

Simulation of the potential visual impacts is a method planners and developers have to determine the appearance of a project before disturbing the landscape. Simulation is an important tool enabling both planners and the public to visualize the changes in the landscape which would result from a proposed project. Simulation provides a forum for discussion of alternative designs and often points out parts of a design that could be improved, reducing visual contrasts and making the project features more compatible with the visual objectives. A variety of simulation techniques are available, varying from artistic renderings, alteration of photographs, to computer graphics (U.S.D.I. Bureau of Land Management 1980). Those techniques which portray the proposal in three dimensions are most effective. Many consulting firms have simulation capabilities.



Rendering on a photograph. Source: Federal Energy Regulatory Commission



Computer perspective drawing. Source: U.S.D.A. Forest Service 1987.

Summary

The quality of the visual resource is important to the public. Since water features attract the public, hydropower developers have an opportunity and an obligation to manage the project visual resources in a way which will protect those resources for present and future visitors. By carefully using a visual resource management system of inventory, analysis, and simulation, projects can be designed that effectively reduce adverse visual impacts. The literature cited in this paper provides excellent sources for the reader to obtain a working knowledge of visual resources and their management.

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AUTHOR'S BACKGROUND

Colorado State University, BS Forest Recreation 1963.
University of Wisconsin, MS Landscape Architecture 1971.
Staff Landscape Architect, Federal Energy Regulatory Commission,1987 to present. (825 N. Capital, Washington, D.C. 20426)
USDA, Forest Service 1964 - 1987, stationed in Arizona, New Mexico, Colorado, Oregon, Michigan, Indiana, and Wisconsin.

SESSION 9:

ENVIRONMENTAL PLANNING

Chairperson: B. Winson
Ontario Ministry of the Environment

The New Ontario Small Hydro Site Release Policy

By
I.M. Crawford

13

MINISTRY OF NATURAL RESOURCES

POLICY LM-8.08.08
SMALL HYDRO POWER SITES

The Government of Ontario, through the Ministries of Natural Resources and Energy has a policy to encourage the development of small, privately owned, hydroelectric generating stations. The purpose of this policy is to: 1) utilize Ontario's indigenous resources to the maximum possible extent, 2) diversify the provincial electricity supply options, 3) stimulate local economies, and 4) develop a strong Ontario manufacturing and development industry. The development of hydroelectric resources is consistent with the principles of Integrated Resource Management and Crown Land as a Development Tool.

Water power development usually involves Crown land under the administration and control of the Ministry of Natural Resources. This Ministry has the responsibility of ensuring that proposed developments are fully reviewed with regard to the concept of integrated resource management before being offered. The disposition and development of sites is governed by the Lakes and Rivers Improvement Act, the Public Lands Act and the Environmental Assessment Act.

As the ultimate purchaser of electricity produced from most waterpower developments, Ontario Hydro will be closely involved in the release of potential sites. The Ministry will work with Ontario Hydro to identify optimal development of watersheds and systems. In some cases, Ontario Hydro will lease large sites to determine if development by the utility is in the best interest of its ratepayers. For the large sites leased to Ontario Hydro the processes described in this policy do not apply.

A proposal to develop a Crown site may be initiated by a proponent or by the Ministry of Natural Resources. However, the final decision concerning the development strategy for the site will be made by the Ministry of Natural Resources in consultation with other ministries and Ontario Hydro as required. Land Management Branch is the main contact point between MNR, the Ministry of Energy, and Ontario Hydro for small hydro development. District Managers shall ensure that both the Region and Land Management Branch are kept informed as to applications received and their subsequent status (i.e. time of location approval and time of approval of works).

Potential sites are divided into 4 categories:

1. Crown land sites with no existing facilities in place, with an average power capacity of up to 5 megawatts.
2. Crown land sites with no existing facilities in place, with an average power capacity greater than 5 megawatts.
3. Crown land sites with facilities (e.g. dam) in place.

4. Sites where the bed is Crown-owned but one or both banks are owned by private interests.

Potential sites may be offered as follows:

Category 1 sites shall generally be offered on a first come, first served basis.

Category 2 sites may, at the discretion of Land Management Branch, be offered by a call for proposals or on a first come, first served basis.

Category 3 sites shall generally be offered by a call for proposals.

Category 4 sites shall generally be offered on a first come, first served basis.

Further, at the discretion of Land Management Branch, any category 1, 2, or 3 site may be offered by a call for proposals or be exempted from the call for proposal process. For example, a site located close to a remote community not serviced by the provincial utility grid might be offered by a call for proposals in cooperation with Ontario Hydro in order to ensure optimal community benefits and high reliability. Conversely, a site of any category, proposed for development by a proponent who wishes to service his/her nearby business interests (such as a mine or tourist facilities), may be offered to that applicant on a first come, first served basis.

Processing of applications and disposition of sites shall be subject to the following:

a. An applicant must be a resident of Ontario or be a company incorporated in Ontario. The initial applicant must be the ultimate lessee of the Water Power Lease Agreement or, in the case of a corporation, be at least an equal partner in the company.

b. In first come, first served situations, priority shall be given to the applicant who submits the "first application", defined as the initial complete application and location plan received by the MNR District Manager for location approval under the Lakes and Rivers Improvement Act.

c. The number of Crown land sites that may be under development in Ontario by any one proponent at any one time is limited to three. Therefore, MNR will entertain no more than three active applications from any one proponent. If a proponent submits more than three applications, Land Management Branch will notify him/her by registered mail that the excess application(s) must be withdrawn within 15 days and, if the proponent fails to withdraw them, the Ministry will consider the three which were first received and will return the excess one(s) to the proponent.

   After a proponent has completed a development (i.e. when the site is producing electricity), he/she again becomes eligible to apply for a new site, provided always that the sum of sites under development

d. Every applicant shall be advised by the District Manager:

- that certain information specified under item 9 of section 1 of Procedure Directive LM 8.08.01 is required, in advance of the decision making process, for the information of MNR and MOE,
- that the applicant may be required to apply for approvals under the following Acts prior to disposition and/or construction: Navigable Waters Protection Act (Federal), Lakes and Rivers Improvement Act (MNR), Canada Fisheries Act (MNR), and Public Lands Act (MNR),
- that the project may be subject to the Environmental Assessment Act,
- that the applicant, with assistance from the District, may be required to notify the general public and all individuals, groups, and agencies who may be affected by the proposed development,
- that a municipal building permit will be required if applicable,
- that approval of electrical equipment and installation under the Electrical Safety Code (administered by Ontario Hydro) will be required,
- that the safety and maintenance of the proposed facility and liability in the event of accidental or any damage, will be the sole responsibility of the proponent.

e. Within 12 months (to a maximum of 24 months depending on the complexity of the project) after the District Manager advises the applicant of the requirements under item 9, section 1 of the Procedure Directive LM 8.08.01, the applicant shall provide the District Manager with the required information. Failure to provide this information within the time specified by the District Manager may result in cancellation of the applicant's interest.

f. Upon the District Manager's issuance of location approval, the proponent has up to 12 months (or more depending on the complexity of the project) to undertake a feasibility study and submit, to the District Manager, the feasibility study, plans and specifications including detailed construction drawings, for approval of works under the Lakes and Rivers Improvement Act by the MNR Regional Engineer. Failure to submit these plans and specifications within the time specified by the District Manager may result in the cancellation of the proponent's interest.

g. Upon the Regional Engineer's issuance of approval of works, the proponent must pay, to MNR, a deposit equal to $5.00 per kilowatt of estimated power production to be applied to waterpower lease fees and/or land rent. The proponent has a period of up to 48 months to put the site into water power production. If, upon elapse of this time, the site is not in operation, the proponent's interest may be cancelled and the deposit forfeited.

h. Occupation of Crown lands for purposes of headpond flooding, transmission lines, dams, and other pertinent structures, must be authorized under the Public Lands Act by lease, land use permit, and/or licence of occupation, under which annual fees are payable.

i. In connection with the evaluation process used to select the best proposal under the call for proposals process, the examining committee will comprise the District Manager,District Lands Supervisor and Administration Supervisor, an MNR Regional Engineer, the Waterpower Administrator, representatives from Ontario Hydro, and a representative from the Ministry of Energy. The selection criteria will include, but are not limited, to the following:

    (1) The engineering acceptability of the proposal;

    (2) The most efficient use of the water resource and river system for power development;

    (3) The degree to which the proposal considers or mitigates any social and environmental conflicts;

    (4) The proponent's economic analysis and financial projections for the project, related business experience, and/or expertise in developing small hydro sites;

    (5) The proponent's proposed pricing of power sales to Ontario Hydro (if applicable).

    (6) The Waterpower rental rate the proponent is willing to pay. The current rate can be obtained from Land Management Branch. This payment is deferred for 10 years from the beginning of the first calender year of operation. The proponent must state whether the 10 year deferral will be waived or not (if applicable).

j. All water power sites are liable for tax assessment, under either the Assessment Act if the site is in an organized municipality, or the Provincial Land Tax Act if it is not. Information can be obtained from the Regional Assessment Commissioner of the Ministry of Revenue.

k. Except where a proponent offers to pay waterpower rent as part of his/her proposal, waterpower rentals will be waived for the first ten years of energy production, after which the prevailing standard waterpower rate, derived from the consumer price index, will be charged. The 10 year waiver period begins on January 1 of the calendar year in which power production commences.

MINISTRY OF NATURAL RESOURCES
PROCEDURE

SMALL HYDRO POWER SITES

1. CROWN LAND SITES WITH NO EXISTING FACILITIES IN PLACE, WITH AN AVERAGE POWER CAPACITY OF UP TO 5 MEGAWATTS

RESPONSIBILITY		ACTION
District Manager	1.	Receives written notification of interest in a potential waterpower site from a proponent.
	2.	Advises proponent that application for location approval under the Lakes and Rivers Improvement Act must be completed and submitted.
	3.	Upon receipt of application for location approval, date stamps it and sends a copy of the application to the Region and Land Management Branch. Sends acknowledgement to proponent.
Land Management Br.	4.	Reviews application to ensure consistency with policy. Notifies the Region if the application can be processed as intended. Notifies the Ministry of Energy and Ontario Hydro of application.
Ministry of Energy	5.	Advises Land Management Branch of any reports or studies available from the Ministry of Energy.
Ontario Hydro	6.	Reviews application and advises Land Management Branch, within 60 days of receipt, of any concerns regarding interconnection or effects on existing or proposed Ontario Hydro facilities.
Land Management Br.	7.	Reviews Ontario Hydro concerns and Ministry of Energy response and advises Region accordingly.
District Manager	8.	Notifies the proponent of his responsibilities under item "d" of policy Directive LM 8.08.01.

9. Specifies to the proponent, within 30 days of receipt of the application for location approval, the information required at this stage by MNR and MOE. This information will include, but is not limited to, the following:
- purpose,
- location,
- description of the project,
- expected environmental effects,
- proposed mitigation measures,
- physical description of the impoundment area,
- degree and frequency of water level fluctuation in the impoundment area,
- residual downstream flow,
- estimate of the 7Q20 (7 day mean daily flow with a return period of 20 years).
- description of the physical environment before and after the project.

10. Advises the proponent as to the date by which the information in "9" above is required.

11. Informs proponent that he/she, with assistance from the District, may be required to notify the general public and all individuals and agencies who may be affected by the proposed development. Provides the proponent with a list of the agencies and organizations which should be notified.

Proponent

12. Gives public notice and notice to MOE Regional Office by an appropriate method such as posted notice, individual notice,news release, notice in local newspaper, etc. The notice will generally describe the project, state where additional information may be obtained, and request that comments and concerns be submitted to the proponent and to the local MNR District Office.

13. If interested parties request additional information, provides it as expeditiously as possible.

14. Allows a minimum of 30 days for recipient(s) of additional information to make comments/express concerns.

15. Assembles a project information package and submits it to the District Manager, including the results of public consultation and any additional information that has been generated since the

District Manager	16.	Upon receipt of the project information package determines, within 30 days, if the package contains sufficient information on which to make a decision as to whether the project constitutes a major or minor disposition. If there is insufficient information, directs the proponent to provide additional information. Reviews the final information package with the proponent.
	17.	Based on the information provided and review by district staff, determines within 30 days whether the project constitutes a minor or a major disposition. 17a. If it is determined that the development constitutes a minor disposition, issues location approval on condition that the proponent obtain all necessary legislative approvals identified in item "d" of Policy Directive LM 8.08.0l. 17b. If it is determined that the development constitutes a major disposition, advises Region and Land Management Branch of intention to request MOE determination. Provides all information contained in the project information package to the Environmental Assessment Branch of MOE as per Procedure Directive PS 4.02.75, "Disposition of Rights to Crown Properties".
District Manager	18.	When granting location approval, advises the proponent of the time allotted for a feasibility study and submission of plans and specifications, including detailed construction drawings and any conditions, for approval of works. Advises Region and Land Management Branch that location approval has been granted.
Proponent	19.	Carries out feasibility studies or other investigations to determine if the project is viable. If it is, submits 3 copies of the feasibility study, plans, and specifications as per Procedure Directive ES 3.03.03, including detailed construction drawings, to the District Manager who reviews and forwards them to the Regional Engineer.
MNR Regional Eng.	20.	Examines plans, specifications, and construction drawings according to Procedure Directive E.S. 3.03.03. Forwards to Ontario Hydro for verification. If deemed by the regional engineer

District Manager	21.	Collects, from the proponent, a deposit in the form of a letter of credit or other suitable device payable to the Treasure of Ontario equivalent to $5 per kilowatt of estimated power production.
Proponent	22.	During the development period, performs a legal survey of the site and enters into a Water Power Lease Agreement with Land Management Branch.
District Manager	23.	Issues appropriate authority under the Public Lands Act for the land occupied by headpond flooding, transmission lines, dam and other pertinent structures.

2. CROWN LAND SITES WITH NO EXISTING FACILITIES IN PLACE. WITH AN AVERAGE POWER CAPACITY GREATER THAN 5 MEGAWATTS

RESPONSIBILITY		ACTION
Land Management Br.	1.	With assistance from Ontario Hydro, identifies sites that may be offered by calls for proposals.
	2.	Advises Region of interest in releasing a site by a call for proposals.
District Manager	3.	Prepares a report to the Region, which in turn forwards it, after review, to Land Management Branch advising of any potential impediments to release and development of the site.
Land Management Br.	4.	Reviews report and consults with the Minister as necessary. Advises the Region accordingly.
District Manager	5.	If the decision is to offer the site on a first come, first served basis, follows the procedure for Crown Land Sites With No Existing Facilities, With an Average Power Capacity Less Than 5 Megawatts (section 1 of this directive).
Land Management Br.	6.	If the decision is to offer the site by a call for proposals, follows the following procedure. Notifies the Ministry of Energy and Ontario Hydro of intention to offer the site by a call for proposals.

Ministry of Energy	7.	Advises Land Management Branch within 30 days of any reports or studies available from the Ministry of Energy.
Ontario Hydro	8.	Provides Land Management Branch with a package for inclusion in the call for proposals that would include: preferred development options, interconnection requirements, operation limitations, and the specified avoided cost ceiling.
Land Management Br.	9.	Reviews Ministry of Energy and Ontario Hydro responses and advises Region accordingly.
District Manager	10.	Prepares a terms of reference in consultation with Region, Land Management Branch, and Ontario Hydro, outlining all known information about the site. The terms of reference will be used to advise potential proponents: - of operating, environmental, and/or management constraints, - of restoration requirements with which the successful proponent must comply, - of requirements for obtaining preliminary approvals from MNR and MOE, - of the evaluation criteria by which each submission will be judged, - of preferred development options, interconnection requirements, operation limitations, and the specified avoided cost ceiling, - that the disposition may be subject to the Environmental Assessment Act, - that the successful proponent will be required to apply for approvals under the following acts prior to disposition and/or construction: Navigable Waters Protection Act (Federal), Canada Fisheries Act, Lakes and Rivers Improvement Act (MNR), and the Public Lands Act (MNR), - that the successful proponent, with the assistance of the District, may be required to notify the general public and all individuals, groups, and agencies who may be affected by the proposed development.

The terms of reference will also call for the following minimum information required in a proposal:

- purpose,
- location,
- description of the project,
- expected environmental effects,
- proposed mitigation measures,
- physical description of the impoundment area,
- degree and frequency of water level fluctuation in the impoundment area,
- residual downstream flow,
- estimate of the 7Q20 (7 day mean flow with a return period of 20 years),
- description of the physical environmental before and after the project,
- pricing proposal specified by Ontario Hydro.

Forwards a copy of the terms of reference to Region and Land Management Branch for approval.

11. Invites potential proponents, through the various media and through mailing lists of interested parties available from Land Management Branch, to come forward with development proposals. Places advertisements in at least three publications (one local, one regional, and one provincial). The form of the call for proposals will be as dictated by Financial Resources Branch.

12. Establishes a selection committee as per Policy Directive LM 8.08.01, reviews all submissions. A recommendation is forwarded to the Minister for approval.

13. Informs the successful proponent that he/she, with assistance from the District, may be required to notify the general public and all individuals and agencies, including MOE Regional Office, that may be affected by the proposed development. Such notice will be given by an appropriate method such as a posted notice, individual notice, news release, notice in local newspaper, etc. The notice will generally describe the project, state where additional information may be obtained, and request that comments and concerns be submitted to the proponent and to local MNR district office.

Proponent	14.	If interested parties request additional information, provides it as expeditiously as possible.
	15.	Allows a minimum of 30 days for recipient(s) of additional information to make comments/express concerns.
	16.	Assembles a project information package and submits it to the District Manager, including the results of public consultation and any additional information that has been generated since the project proposal stage.
District Manager	17.	Upon receipt of the project information package determines, within 30 days, if the package contains sufficient information on which to make a decision as to whether the project constitutes a major or minor disposition. If there is insufficient information, directs the proponent to provide additional information and reviews this information with the proponent.
	18.	Based on the information provided and review by district staff, determines within 30 days whether the project constitutes a minor or a major disposition. 18.a. If it is determined that the development constitutes a minor disposition, issues location approval on condition that the proponent obtain all necessary legislative approvals identified in item "d" of Policy Directive LM 8.08.01. 18.b. If it is determined that the development constitutes a major disposition, advises Region and Land Management Branch of intention to request MOE determination. Provides all information contained in the project information package to the Environmental Assessment Branch of MOE as per Procedure Directive PS 4.02.75, "Disposition of Rights to Crown Properties".
	19.	When granting location approval, advises the proponent of the time allowed for a feasibility study and submission of engineering plans and specifications, including detailed construction drawings, for approval of works. Advises Region and Land Management Branch that location approval has been granted.

Proponent	20.	Carries out feasibility studies or other investigations to determine if the project is viable. If it is, submits 3 copies of the feasibility study, plans and specifications, including detailed construction drawings, to the District Manager who reviews and forwards them to the Regional Engineer..
MNR Regional Eng.	21.	Examines plans, specifications, and construction drawings according to Procedure Directive E.S. 3.03.03. Forwards to Ontario Hydro for verification. If satisfactory, grants approval of works.
District Manager	22.	Collects, from the proponent, a deposit in the form of a letter of credit or other suitable devise payable to the Treasurer of Ontario equivalent to $5 per kilowatt of estimated power production.
Proponent	23.	During the development period, performs a legal survey of the site and enters into a Water Power Lease Agreement with Land Management Branch.
District Manager	24.	Issues appropriate authority under the Public Lands Act, for the land occupied by headpond flooding, transmission lines, dams, and other pertinent structures.

3. CROWN LANDS SITES WITH FACILITIES (E.G. DAM) IN PLACE

RESPONSIBILITY		ACTION
District Manager	1.	Notifies Region and Land Management Branch of intention to offer site by call for proposals.
Land Management Br.	2.	Notifies the Ministry of Energy and Ontario Hydro of intention to offer the site by a call for proposals.
Ministry of Energy	3.	Advises Land Management Branch within 30 days of any reports and/or studies available from the Ministry of Energy.

Ontario Hydro 4. Provides Land Management Branch with a package for inclusion in the call for proposals that would include: preferred development options, interconnection requirements, and operation limitations.

Land Management Br. 5. Reviews Ministry of Energy response and Ontario Hydro information and advises Region and District Manager accordingly.

District Manager 6. Prepares a terms of reference outlining all known information about the site. The terms of reference will be used to advise potential proponents:

- of operating, environmental, and/or management constraints,
- of restoration requirements with which the successful proponent must comply,
- of requirements for obtaining preliminary approvals from MNR and MOE,
- of the evaluation criteria by which each submission will be judged,
- of preferred development options, interconnection requirements, and operation limitations,
- that the disposition may be subject to the Environmental Assessment act,
- that the successful proponent may be required to apply for approvals under the following acts prior to disposition and/or construction: Navigable Waters Protection Act (Federal), Canada Fisheries Act, Lakes and Rivers Improvement Act (MNR), and the Public Lands Act (MNR),
- that the successful proponent, with assistance from the District may be required to notify the general public and all individuals, groups, and agencies who may be affected by the proposed development.

The terms of reference will also call for the following minimum information required in a proposal:

- purpose,
- location,
- description of the project,
- expected environmental effects,
- proposed mitigation measures,
- physical description of the impoundment area,

- degree and frequency of water level fluctuations in the impoundment area,
- residual downstream flow,
- estimate of the 7Q20 (7 day mean flow with a return period of 20 years).
- description of the physical environment before and after the project.

Forwards a copy of the terms of reference to Region and Land Management Branch for approval.

7. Invites interested parties, through the various media and through mailing lists of interested parties available from Land Management Branch, to come forward with development proposals. Places advertisements in at least three publications (one local, one regional, and one provincial). The form of the call for proposals will be as dictated by Financial Resources Branch.

8. Establishes a selection committee as per Policy Directive LM 8.08.01, reviews all submissions. A recommendation is forwarded to the Minister for approval.

9. Informs the successful proponent that he/she, with assistance from the District, may be required to notify the general public and all individuals and agencies, including MOE Regional Office, that may be affected by the proposed development. Such notice will be given by an appropriate method such as a posted notice, individual notice, news release, notice in local newspaper, etc. the notice will generally describe the project, state where additional information may be obtained, and request that comments and concerns be submitted to the proponent and to local MNR district office.

Proponent

10. If interested parties request additional information, provides it as expeditiously as possible.

11. Allows a minimum of 30 days for recipient(s) of additional information to make comments/express concerns.

12. Assembles a project information package and submits it to the District Manager, including the results of public consultation and any additional

information that has been generated since the project proposal stage.

District Manager	13.	Upon receipt of the project information package determines, within 30 days if the package contains sufficient information on which to make a decision as to whether the project constitutes a major or minor disposition. If there is insufficient information, directs the proponent to provide additional information and reviews this information with the proponent.
	14.	Based on the information provided and review by district staff, determines within 30 days whether the project constitutes a minor or major disposition. 14.a. If it is determined that the development constitutes a minor disposition, issues location approval on condition that the proponent obtain all necessary legislative approvals identified in item "d" of Policy Directive LM 8.08.01. 14.b. If it is determined that the development constitutes a major disposition, advises Region and Land Management Branch of intention to request MOE determination. Provides all information contained in the project information package to the Environmental Assessment Branch of MOE as per Procedure Directive PS 4.02.75, "Disposition of Rights to Crown Properties".
	15	When granting location approval, advises the proponent of the time allowed for a feasibility study and submission of engineering plans and specifications, including detailed construction drawings, for approval of works. Advises Region and Land Management Branch of intention to grant location approval.
Proponent	16.	Carries out feasibility studies or other investigations to determine if the project is viable. If it is, submits 3 copies of the plans and specifications as per Procedure Directive ES 3.03.02, including detailed construction drawings, to the District Manager who reviews and forwards them to the Regional Engineer.
MNR Regional Eng.	17.	Examines plans, specifications and construction drawings according to Procedure Directive E.S. 3.03.03. Forwards to Ontario Hydro for verification. If satisfactory, grants approval of works.

District Manager	18.	Collects, from the proponent, a deposit in the form of a letter of credit or other suitable devise payable to the Treasurer of Ontario equivalent to $5 per kilowatt of estimated annual power production.
Proponent	19.	During the development period, performs a legal survey of the site and enters into a Water Power Lease Agreement with Land Management Branch.
District Manager	20.	Issues appropriate authority under the Public Lands Act, for the land occupied by headpond flooding, transmission lines, dams, and other pertinent structures.

4. SITES WHERE THE BED IS CROWN OWNED BUT ONE OR BOTH BANKS ARE OWNED BY PRIVATE INTERESTS

RESPONSIBILITY		ACTION
District Manager	1.	Upon interest being expressed by a potential proponent, takes no action until proponent has clearly established a legal interest in the portions of the site that are private land.
	2.	Follows the procedure for Crown Land Sites With No Existing Facilities, With an Average Power Capacity Less Than 5 Megawatts (section 1 of this directive).

Environmental Law in Small Hydro

By
H. Dahme

14

SESSION TOPIC Environmental Planning

TITLE Environmental Law in Small Hydro

AUTHOR(S) Harry Dahme

ABSTRACT

As increasing attention is drawn to the development potential for small hydro development, increased attention will also be drawn to the environmental implications of such development.

Although small hydro power development has not been subjected to the same scrutiny that has been directed toward larger developments with respect to environmental implications, there is still the need to consider the environmental implications in the context of existing environmental law.

There is, in Canada and in other Commonwealth nations, a body of common law imposing certain requirements on small power development. The law pertaining to riparian rights, nuisance and negligence may have significant impact at the planning, development and operating stages of a development.

Further, increasing public awareness of environmental issues increases the importance of ensuring that all necessary permits are properly obtained and that the rights of all of those affected are dealt with in accordance with the principles of natural justice and fairness.

In addition, there is federal and provincial legislation which has direct implications on development of small hydro and considerations of that legislation may be crucial to the particular development.

There is also, finally, the issue of native rights which arises in the context of developments in proximity or on reserves and to the extent that these issues are closely related to environment issues, various considerations in this context will also be addressed.

In all of the above cases, the law will be briefly discussed and the potential implications of small hydro developments will be raised for consideration so as to assist both in future planning and in addressing any particular problems which may already have arisen as a result of a particular development.

AUTHOR'S BACKGROUND

Harry Dahme has a B.Sc. from the University of Toronto and is a graduate of Osgoode Hall Law School. He practices exclusively in the area of Environmental and Municipal Planning Law with the firm of David Estrin, Barristers & Solicitors. He has appeared before virtually every level of court both federally and provincially and in front every provincial tribunal concerned with environmental issues on matters as diverse as applications for approval of a liquid natural gas facility to waste management matters.

ENVIRONMENTAL LAW AND SMALL HYDRO

As increased attention is drawn to the development potential for small hydro development, increased attention will also be drawn to the environmental implications of such development.

Although small hydro development has not been subjected to the same scrutiny that has been directed toward larger developments with respect to environmental implications, there is still the need to consider, during the planning, construction and operation phases, the environmental implications in the context of existing environmental law.

There is, in Canada and in other Commonwealth nations, a body of common law which can impose certain requirements in respect of small hydro. The law pertaining to riparian rights, nuisance and negligence may have a significant impact at the planning, development and operating stages of a project.

Further, there is federal and provincial and municipal legislation which has direct implications on development of small hydro and considerations of that legislation may be crucial to the particular development.

In addition, increasing public awareness of environmental issues increases the importance of ensuring that all necessary permits required pursuant to the applicable legislation are properly obtained and that the rights of all of those affected are dealt with in accordance with the principles of natural justice and fairness.

There is also, finally, the issue of native rights which arises in the context of developments in proximity or on reserves. To the extent that these issues are closely related to environmental issues, various considerations in this context should be addressed.

In respect of each of these three areas, the common law, legislation and native rights, the law will be briefly discussed and the potential implications for small hydro will be raised for your consideration so as to assist both in future planning and in addressing any current problems.

1. Common Law

The common law is a body of law which has been developed through time by judges in Commonwealth countries and unless it has been specifically displaced by legislation, it continues to have the force of law. Consequently, it must be considered in connection with any development or facility.

The common law creates rights and allows for court actions to be commenced in order to protect those rights.

The three particular causes of action which are of the most significance in respect of small hydro are:

a) riparian rights

b) nuisance

c) negligence

a) Riparian Rights

The law as to riparian rights seems to be quite clear.

The general principle is that the owner of lands which abut a waterway in a known and defined natural channel is entitled to have the water flow in its natural state both as regards to quantity and quality.

The basic principle is that all owners of lands which abut onto a waterway may reasonably use the water subject to the rights of other riparian owners. The right to the benefit and advantage of the water is not an absolute one in that sense, but it is subject to the rights of other riparian owners.

There are limitations as to the use of the water. The water can be used for ordinary uses, and only for such other uses as are reasonable provided that the water is then returned substantially undiminished in volume and unaltered in character to the stream. In other words, it may be diverted but it must be returned to the water course without a diminution in quantity or quality.

An example of where this might be applicable is that a small hydro development may impound waters to the detriment of the downstream users. In that case, those downstream users could conceivably have a right of action as against the owners of the small hydro development if the impounding of the water is unreasonable and damage is caused.

Correspondingly, if there are a series of small hydro users on a particular river, each one of them has a right to a certain flow, subject to the rights of the other parties.

An interesting factor to be considered is that along some waterways there exists a 66' shoreline road allowance, and in such cases the only riparian owner would be the Crown and not any of the private landowners adjacent to the body of water. They would consequently have no rights to complain as to any alteration in quantity or quality of the water.

In the event that there is an interference with riparian rights, the remedies available are an award of damages, or an injunction. An injunction is a Court order requiring the person interfering with the flow of water to stop from interfering with that flow.

b) Nuisance

A nuisance is caused when there is damage to property or an unreasonable interference with the enjoyment of property as the result of certain activities.

The cases wherein this cause of action has arisen involve everything from the operations of a gravel pit to air emissions from a factory interfering with the greenhouse operations of an individual.

It should also be noted that the escape of a non-natural substance also creates a cause of action. A non-natural substance could be an excessive flow of water.

The remedies available in respect of a nuisance are an injunction, which is, I should add, the usual remedy, or damages in cases where the nuisance is less extreme.

The relevance of this cause of action to small hydro relates to construction activities, damage to shoreline properties, and any nuisances arising out of operations, such as in the case of inadequate soundproofing with resultant impact upon neighbours.

c) Negligence

Negligence essentially takes place where certain conduct falls below the standard accepted in the community.

In order to establish that negligence has taken place, the person complaining must establish first of all that a duty of care exists, that second there has been a breach of that duty, and third that damages resulted from that breach. In addition, there are other things that need to be proven such as a direct relationship between the damage caused and some action taken by or on behalf of the person against whom the claim is made.

The type of action that could give rise to a cause of action in negligence are limited only by your imagination, and perhaps the best strategy to employ is to ensure that all reasonable care is taken to avoid any damage from taking place.

This very brief review of some of the common law causes of action should impress upon you the importance of good planning so as to ensure that off-site impacts do not take place or are at least limited in their scope. It also becomes a factor in considering whether or not compensation should be provided for, for persons affected, or at least whether or not a reserve fund of some sort should be established in order to address possible claims.

It can't be stressed enough how important good planning and good operations and maintenance are, if only for the purpose of ensuring that you don't find yourself before the courts answering some form of claim.

It should be noted that some of the consequences of losing such action could be very serious indeed, and that is precisely why your attention is directed toward the importance of good planning, operations and maintenance.

2. Legislation

Legislation is important not only because it relates to the obtaining of permits necessary for the development of a particular small hydro project, but also because failure to comply with legislation can have serious consequences.

The Ontario Ministry of Energy has a very good guide to the approval process which sets out in summary form some of the legislation in Ontario applicable to small hydro. All three levels of government have laws which may affect small hydro and some of these laws are discussed below.

a) Federal Legislation

The applicable federal legislation includes The Navigable Waters Protection Act, The Fisheries Act, The Dominion Water Power Act and The International River Improvement Act.

In addition, if the project is being undertaken by or on behalf of a federal government department, if it may have an environmental effect on an area of federal responsibility, if the federal government makes a financial contribution, or if the project is located on federal property, then the federal environmental assessment and review process ("EARP Process") applies and a very complex environmental approvals process needs to be undergone in order to assess the environmental impact of the proposal. Required to be addressed in such a case are the existing environment, a description and scope of the proposed development, potential impact, mitigation measures and a net effects analysis.

I had mentioned earlier that it is also very important to ensure that to the extent that any approvals are required, it should be ensured that all the proper procedures in obtaining those approvals are followed. I raise it at this point in connection with the federal environmental assessment and review process, insofar as failure to properly conduct a study in accordance with that process may lead to court battles with opponents and consequent delay.

That applies to all of the approvals that are required.

Needless to say, it should be ensured that all of the necessary approvals are obtained, but it should also be ensured that they are obtained in the proper fashion so as to prevent the issuance of the permits obtained subsequently being questioned in the courts. The delay could be substantial, and it could be costly.

Probably the most common ground for challenging the issuing of permits is failure to comply with the principles of fairness and natural justice. In that regard, attention should be paid in the planning process to who may be affected and then the decision will have to be made as to whether or not they should be notified of the applications, in order to ensure that, when the permits are issued, those individuals cannot then complain that their concerns were not heard and considered.

This applies to all of the approvals required under all provincial legislation.

Before leaving this matter of federal legislation, I should just note that fines under The Fisheries Act can be substantial and, therefore, in the planning process it should be ensured that the impact on fish habitat is minimized.

In that regard, there are incentives to individuals prosecuting under The Federal Fisheries Act insofar as half of the fine goes to the prosecutor, and it is not unusual for private individuals to commence prosecutions for failure to comply with the provisions of the Act.

It should also be considered during construction and development and, in particular, what that means is adequate storm water management during construction and efforts being made to ensure minimum downstream impact during construction.

b) Provincial Legislation

I don't propose to discuss all of the approvals necessary to be obtained pursuant to provincial legislation except to note briefly what they are.

i) Lakes and Rivers Improvement Act
ii) Environmental Assessment Act
iii) Water Resources Act
iv) Public Lands Act
v) Heritage Act
vi) Conservation Authorities Act
vii) Beds of Navigable Waters Act

These are only some of the statutes which may apply, and depending on the nature of the project, there may be a number of other Acts which have application.

As was stressed in connection with the federal legislation, it should be ensured that all the necessary permits are obtained, and that to the extent that there may be other parties directly affected, decisions need to be made as to whether or not those parties should be notified of the applications for approvals.

There are three specific pieces of legislation that I would briefly like to talk about.

The Environmental Protection Act creates offences for polluting and the proponent would be well advised to consider during planning, construction and operation, the prohibitions under that Act. That is particularly important insofar as recent changes to the Act make directors and officers of corporations directly liable and subject to jail terms as well as substantial fines.

The Ontario Water Resources Act concerns itself with water pollution, and similarly attention should be had to the prohibitions pursuant to that legislation so as to ensure that the proponent would not be subject to the penalties under that Act.

Finally, there is the Environmental Assessment Act. That legislation currently does not apply to private companies except in specific circumstances, however, there is a move afoot to make it applicable to private sector undertakings. In addition, opponents to a particular proposal may request the Provincial Cabinet to make a project subject to the Environmental Assessment Act.

In the event that the Environmental Assessment Act becomes applicable, an extensive document entitled the "Environmental Assessment Document" is required to be prepared. The document must address the purpose of the undertaking, the rationale for the purpose of the undertaking, alternatives to the undertaking, alternative methods to the undertaking, and it must conduct an evaluation of advantages and disadvantages and net effects of a particular undertaking.

Most recently, the Minister has required larger scale energy from waste facilities (EFW) to meet the requirements of the Environmental Assessment Act.

c) Municipal Legislation

Municipalities have the power to pass by-laws in respect of a number of matters, and efforts should be made to ensure that those by-laws are complied with.

Specifically, municipalities may have by-laws in respect of noise, outside storage laws, and other matters.

All of these matters should be considered during planning, construction and operation.

Failure to comply may result in fines being levied up to $2,000 per day. Over time those fines could become substantial in their total amount, hence the comment that they should be considered seriously.

3. Native Rights

This is perhaps a topic which in the past has had greater relevance in the West, however, it is a topic which is becoming increasingly relevant in the East.

The relative importance of considering native rights depends upon a number of factors, including the province that you are in, whether or not potential land claims exist, whether or not existing reserve lands may be impacted.

These considerations can be particularly relevant insofar as small hydro opportunities may exist on reserve lands or in close proximity to reserve lands, or transmission right-of-ways may be required across reserve lands.

The issue frequently is a complex one involving the federal government and the provincial government as well as the band council, and a proponent can be best advised to give careful consideration to native rights during planning.

A successful land claim could have a substantial impact on a particular project. Large scale water diversions or transmission lines could have significant impact on certain treaty rights, such as hunting and fishing rights.

Interference with established rights may give rise to litigation and resulting damage claims, and it is usually best, if at all possible, to resolve those disputes prior to actual construction.

Conclusion

That is a brief summary of the applicable law. The reason that this has been put into the context of environmental law is that environmental law encompasses each one of the areas discussed and requires a working knowledge in respect of each of the areas discussed.

Although alot of issues have been raised, it should be emphasized that careful and complete planning, proper construction, and good management are the way to avoid any of the pitfalls that have been discussed, provided that there is consideration given to all of the factors which have been raised.

The Federal Energy Regulatory Commission's Experience in Analyzing Cumulative Impacts on River Basins

By
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SESSION TOPIC Environmental Planning

TITLE The Federal Energy Regulatory Commission's Experience In Analyzing Cumulative Impacts in River Basins

AUTHOR(S) Lee Emery

ABSTRACT

In the mid-1980's, the Federal Energy Regulatory Commission's staff began assessing the cumulative environmental impacts attributable to licensing multiple hydropower projects in river basins. The staff designed environmental documents to meet the intent of the National Environmental Policy Act of 1969. Initially, the staff developed a Cluster Impact Assessment Procedure (CIAP) and used it to assess multiple hydropower project impacts in three river basins in the western United States: the Owens in California, the Snohomish in Washington, and the Salmon in Idaho

In early 1985, the staff identified a need for cumulative impact analysis in 61 river basins located throughout the United States. These basins contained 264 proposed hydropower projects The staff assessed the potential cumulative environmental impacts of these basins using basin-wide environmental impact statements (EIS's) and environmental assessments (EA's). The By April 1988, all but 80 of the 264 projects had undergone NEPA analysis. River Basin EIS's were used to analyze 2 of the 61 river basins, the Ohio River Basin in Ohio, and the Snake River Basin in Idaho. Cumulative EA's were used to analyze the cumulative impacts in most of the other basins.

The Commission has received mixed reactions from the public on the methodologies used to assess cumulative impacts in river basins. The verdict on future use of the CIAP remains undecided. EA's and EIS's will continue to provide the most workable methodology for evaluating cumulative environmental problems from single or multiple hydropower development in river basins. In these endeavors, the Commission has gained a tremendous learning experience that will help future decisionmaking.

AUTHOR'S BACKGROUND

Lee Emery has been with the Federal Energy Regulatory Commissio for over 2 1/2 years, where he has been actively involved in assessing cumulative impacts of multiple hydropower projects on environmental resources in river basins. He previously worked for 12 years with the U.S.Fish and Wildlife Service (FWS) in various multidisciplinary projects. Lee has taught at the FWS Fisheries Academy, worked in fisheries management and environmental services, and published numerous research papers on fish-

THE FEDERAL ENERGY REGULATORY COMMISSION'S EXPERIENCE IN ANALYZING CUMULATIVE IMPACTS IN RIVER BASINS

by

Lee Emery

Introduction

The Federal Energy Regulatory Commission (Commission) became involved in assessing cumulative impacts associated with developing multiple hydropower projects in individual river basins in the early 1970's. In the mid-1970's, the Office of Energy Systems of the Federal Power Commission (a predecessor of the Commission), contracted with a firm to develop methodologies for completing environmental impact statements (EIS) on hydropower development (Federal Power Commission, 1975) and the staff completed an internal report on the Connecticut River Basin that was one of the first basin-wide evaluations of the environmental effects of developing multiple hydropower projects in a river basin (Federal Power Commission, 1976). Although these two documents recognized the intent of the National Environmental Policy Act of 1969 (NEPA),it was not until the mid-1980's that cumulative impact assessment was refined as a workable tool and the Commission acknowledged the Council on Environmental Quality's (CEQ) definition of cumulative impacts, as defined in NEPA (Federal Energy Regulatory Commission, 1987a).

Hydropower Legislation

Between 1978 and 1981, Congress passed legislation aimed at establishing energy independence for the country and its citizens. Congress sought to lessen our dependence on fossil fuels, particularly on the use of imported oil. Four laws were passed that were particularly important in creating economic and procedural incentives for promoting the development of renewable energy resources and for providing a catalyst for attaining national energy independence. Some people believe these four laws offered monetary incentives that produced a national hydropower boom or "hydro rush" of unprecedented proportions. Neither Congress nor prospective energy developers envisioned that the development of renewable energy resources could contribute to the degradation of important natural resources or could cause potential cumulative adverse impacts on natural resources (Johnson, 1983; Eckberg, 1985).

The first law, the Public Utilities Regulatory Policy Act of 1978 (PURPA), required electric utilities to purchase power from alternative producers at a price not to exceed avoided costs. The second law, the Energy Security Act of 1980, provided for the exemption of qualifying small-scale hydropower projects from Part

I of the Federal Power Act. The third law, the Crude Oil Windfall Profits Tax Act of 1980, provided an 11-percent energy tax credit for the development of small-scale hydropower projects. The fourth law, the Economic Recovery Tax Act of 1981, revised the rules for recovering costs associated with depreciable assets and provided an accelerated depreciation schedule for certain hydroelectric facilities. Table 1 shows the more than tenfold increase in applications for licenses and exemptions filed between 1978 and 1984 as a direct result of these four laws. Only PURPA continue to provide economic incentives today.

River Basin Assessment

In July 1985, the Commission's Office of Hydropower Licensing created a River Basin Assessment Section to address hydropower license applications that were being held up from processing because of the need for specifically addressing the potential of the projects to cause cumulative adverse impacts on natural resources in river basins.

The Commission's efforts to evaluate cumulative impacts, spurred on by legislative initiatives, followed many different approaches. These various methodologies and techniques continue to be revised until an optimal methodology or technique is developed. This paper provides a brief overview of the types of methodologies and techniques the Commission's staff uses to assess the cumulative impacts of developing multiple hydropower projects in river basins.

The potential for cumulative impacts to occur from the development of multiple hydropower projects in river basins gained importance when in 1982, various petitioners intervened on hydropower projects proposed for the Salmon River in Idaho and the Snohomish River in Washington (Bodi, 1985; Stoiaken, 1985). The National Wildlife Federation, the Washington Department of Fisheries, Washington Department of Wildlife, National Marine Fisheries Service, the U.S. Fish and Wildlife Service, and various Indian tribes were concerned about the large numbers of hydropower projects proposed for these two basins and the potential for cumulative impacts to occur. At about the same time, the California Water Control Board and other groups were voicing concerns about the potential for cumulative impacts in the Owens River Basin, California, and intervened on projects proposed in that basin.

Cluster Impact Assessment Procedure

In response to petitioners and the public's concern, the staff developed a Cluster Impact Assessment Procedure (CIAP) with the purpose of: identifying basins where there was a potential for adverse environmental impacts to occur from a clustering of hydropower projects; determining the geographic extent of the impacts caused by the hydropower projects (cluster size);

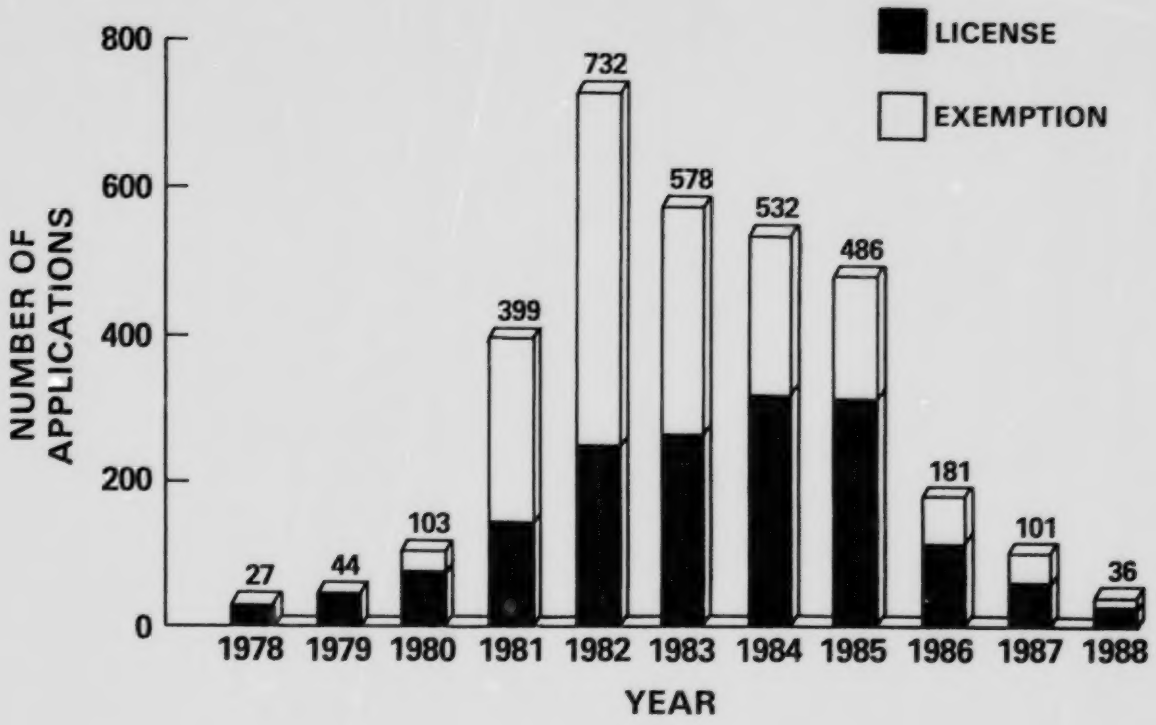

Table 1. Number of license and exemption applications for hydropower projects submitted between January 1978 and May 1988. The increase in numbers of applications between 1978 and 1986 reflect the influence of favorable legislation passed by Congress (Source: the staff).

determining the interaction of target resources (important resources) with proposed and existing hydropower projects; using the procedure to prepare appropriate NEPA documents. The resulting NEPA document could be an EIS or environmental assessment (EA).

The staff held public meetings at various locations in western states and issued public notices requesting comments from the public on the CIAP. Initially, the staff identified 22 river basins (figure 1), containing 166 proposed hydropower projects, as study areas where there was potential for adverse impacts on the environment from multiple hydropower development. In December 1984, the Commission directed the staff to prepare a CIAP for three river basins, the Owens River Basin in California, the Salmon River Basin in Idaho, and the Snohomish River Basin in Washington (figure 1).

The CIAP is divided into four principal phases (figure 2): (1) a geographic sort that determines the geographic area and the target resources of concern; (2) a resource sort that identifies projects with the potential for adversely affecting target resources; (3) a multiple project assessment phase that uses a matrix analysis (a rectangular arrangement of numbers representing numerical values assigned to resources that are arranged in several rows and columns to facilitate multivariate grouping, factor analysis, or for determining other relationships) to determine the magnitude of the impacts of the proposed hydropower projects on the target resources; and (4) document compliance with NEPA. Participation by the public, resource managers, developers, and concerned parties in the process is tantamount to success of the procedure. The staff received mixed responses and participation by the parties concerned in implementing the three CIAP's.

The Argonne National Laboratory in Chicago, Illinois, and the Oak Ridge National Laboratory in Oak Ridge, Tennessee, assisted the staff in completing the three CIAP's. The finished NEPA products were completed in October 1986 for the Owens River Basin (Federal Energy Regulatory Commission, 1986a), in June 1987 for the Snohomish River Basin (Federal Energy Regulatory Commission, 1987b), and in July 1987 for the Salmon River Basin (Federal Energy Regulatory Commission, 1987c). Out of the seven projects applications analyzed for the Owens River Basin, the Commission dismissed four projects, put one project on hold for additional information, and issued two licenses. The Commission has acted on 3 of the 6 project applications under consideration in the Snohomish River Basin, three projects were denied and three projects were delayed for further consideration. The 15 projects under consideration in the Salmon River Basin are pending Commission action.

The use of the CIAP in assessing cumulative impacts caused by potential hydropower projects has been controversial (Evans,

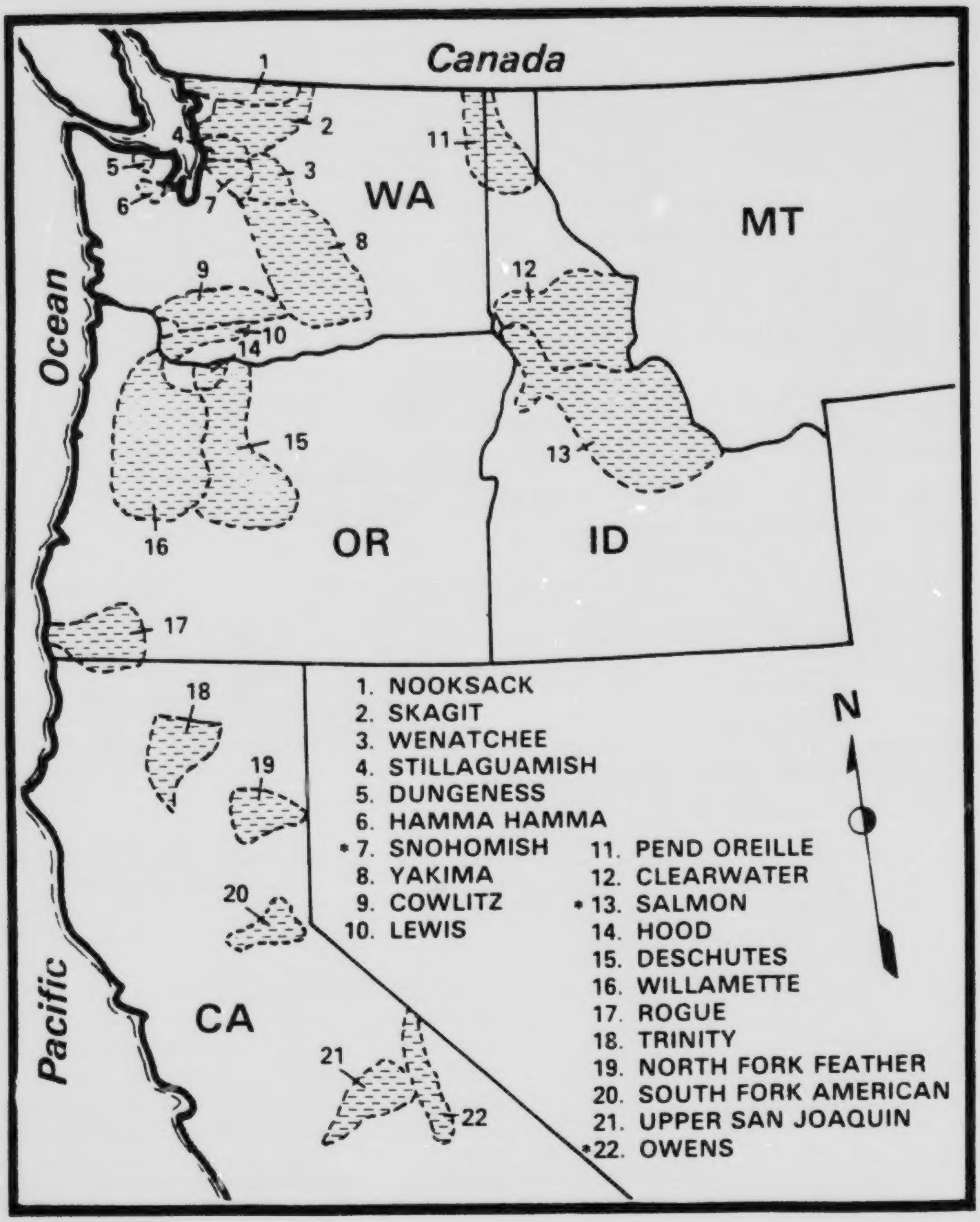
Canada
WA
MT
OR
ID
CA
Pacific Ocean
N
1. NOOKSACK
2. SKAGIT
3. WENATCHEE
4. STILLAGUAMISH
5. DUNGENESS
6. HAMMA HAMMA
* 7. SNOHOMISH
8. YAKIMA
9. COWLITZ
10. LEWIS
11. PEND OREILLE
12. CLEARWATER
* 13. SALMON
14. HOOD
15. DESCHUTES
16. WILLAMETTE
17. ROGUE
18. TRINITY
19. NORTH FORK FEATHER
20. SOUTH FORK AMERICAN
21. UPPER SAN JOAQUIN
*22. OWENS

Figure 1. River basins identified as potential areas where cumulative impacts could occur from the development of multiple hydropower projects. Asterisks indicate basins where CIAP has been approved (Source: the staff).

CLUSTER IMPACT ASSESSMENT PROCEDURE

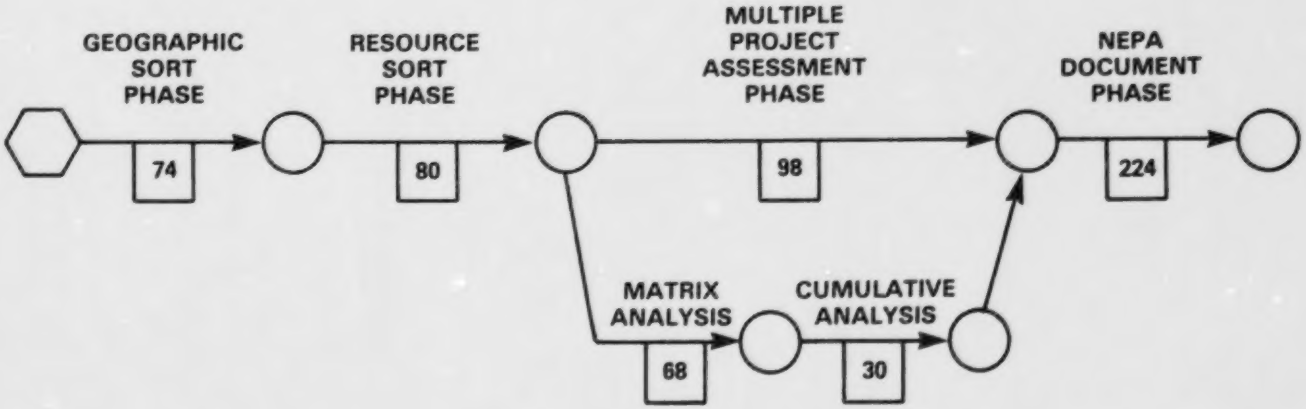
GEOGRAPHIC SORT PHASE
74
RESOURCE SORT PHASE
80
MULTIPLE PROJECT ASSESSMENT PHASE
98
NEPA DOCUMENT PHASE
224
MATRIX ANALYSIS
68
CUMULATIVE ANALYSIS
30

Figure 2. A timeline representing the four phases of the cluster impact assessment procedure (CIAP). A total of 476 days are needed to complete the NEPA document using the CIAP (Source: the staff).

1985; Feil, 1985; and Proett, 1987). The Commission has made no decision on whether to use CIAP in other river basins.

At about the same time the staff was developing the CIAP, California became interested in a number of hydropower projects proposed within its state boundaries. California was instrumental in prompting the 98th Congress, through section 306 of the Energy and Water Appropriation Act of 1983 (Public Law 98-50), to require the Commission to update a comprehensive water resources analysis of Madera, Mariposa, Merced, and Fresno Counties, California. This law also imposed a construction moratorium on exemptions and licenses issued for hydropower projects on rivers and creeks in these counties, and only allowed modifications to any issued preliminary permits (a preliminary permit does not authorize project construction, rather a permit provides an opportunity for an applicant to study the environmental, engineering, and economic feasibility of developing hydropower at a site), exemptions, or licenses if these modifications were based on the results of the comprehensive water resources analysis (Russo, 1985). Congress says nothing about cumulative impacts in section 306, but the broad nature of the task led to a narrowing of the study into two parts: (1) water use and development in selected watersheds in the four-county area, and (2) a comprehensive examination of hydropower preliminary permits, exemptions, and licenses which, in turn, led to the identification of 10 target resources in the area and the potential for 12 hydropower projects to affect these target resources (Russo, 1985). Methodologies used to assess cumulative impacts in the Upper San Joaquin River Basin paralleled those that would be used in the CIAP studies for the Owens, Salmon, and Snohomish River Basins.

The Commission issued a contract to the Oak Ridge National Laboratory to prepare the Upper San Joaquin River Basin report. A draft report was issued in August 1984 and a final environmental impact analysis report was issued in September 1985 (Federal Energy Regulatory Commission, 1985a). It was thought that the report could serve as a basis for any future studies using CIAP in the basin.

The California State Water Resources Control Board also completed an independent analysis of the cumulative impacts of hydropower development in the Upper San Joaquin River Basin. A draft document was released in December 1985 (ESA Planning and Environmental Services, 1985), but no final document was ever completed. California also examined the cumulative impacts associated with hydropower development in other basins in California, including the Trinity River Basin in northern California (Oscar Larson and Associates, 1984).

In 1985, when the Commission issued a public notice in the Federal Register requesting comments on the use of CIAP in the Owens, Salmon, and Snohomish River Basins, it also requested comments on whether the CIAP or a similar procedure should be applied to 22 basins identified by the staff or to any other river basins in the country (figure 1). From the comments received, the staff developed a list of 61 river basins where there was a potential for cumulative impacts from the development of multiple hydropower projects (table 2). These 61 river basins contained 264 proposed hydropower projects (the total number of projects excludes preliminary permits). By April 1988, 152 projects had undergone the required NEPA analysis and the Commission had acted on the projects by issuing a license, issuing an exemption, dismissing them, or taking no action because the application was withdrawn; 32 projects had undergonethe required NEPA analyses and were awaiting Commission action,and 80 projects needed NEPA analysis.

Other Cumulative Impact Assessment Methodologies

Two methodologies were used to assess the cumulative impacts of hydropower projects proposed in the 61 river basins; river basin EIS's and cumulative EA's. River basin EIS's were prepared for two river basins, the Upper Snake River (Federal Energy Regulatory Commission, 1987d) and the Ohio River (Federal Energy Regulatory Commission, 1988). The Upper Snake River EIS evaluated 5 projects and the Ohio River EIS evaluated 24 projects. Both EIS's have been released as draft documents for public comment. The official public commenting period for the Snake River EIS has ended, and the commenting period for the Ohio River EIS ends on July 5, 1988. The Snake River EIS was done entirely by the Commission's staff; the Ohio River EIS was completed under a contract with the Oak Ridge National Laboratory.

The river basin EIS-approach is an involved and lengthy process. The river basin EIS-approach is selected only when there is a potential for significant cumulative adverse impacts on target resources identified in a basin. The Snake River and Ohio River draft EIS's each took about 1 year to complete.

The river basin EIS is in some ways similar to a CIAP, except that there are not as many formal meetings with the public and the river basin EIS begins with the assumption that an EIS will be the final NEPA product. For example, before writing the Snake River Basin EIS, the staff made a preliminary analysis that indicated that two of the five proposed projects would have required project-specific EIS's.

In 1985, the staff also varied the approach for a river basin EIS. At about the time when the draft EIS for the Hamma Hamma Project (FERC Project No. 3178), Washington, was completed (Federal Energy Regulatory Commission, 1985b), cumulative impact concerns were becoming an issue. An addendum to the draft EIS stated that the Commission would consider the cumulative impact issue separately at a later date. On August 15, 1985, the Commission sent a memorandum to appropriate resource agencies, tribes, and other interested parties, specifically soliciting

Table 2. River basins identified by state as having the potential for cumulative impacts to occur from the development of multiple hydropower projects (Source: the staff).*

River Basins	State(s)
Arkansas	Arkansas, Kansas, Oklahoma, Missouri (MO), Colorado
Consumnes	California (CA)
Kern	CA
Kings	CA
Merced	CA
Middle Fork American	CA
*Mono Lake	CA
North Fork American	CA
North Fork Feather	CA
Owens	CA
Pit	CA, Oregon (OR)
*South Fork American	CA
Trinity	CA
Upper Klamath	CA, OR
Upper San Joaquin	CA
Yuba	CA
Connecticut	Connecticut, Massachusetts (MA), New Hampshire (NH), Vermont
Clearwater	Idaho (ID)
Henry's Fork	ID
Pend Orielle	ID, Washington (WA)
Salmon	ID
*Upper Snake	ID, Wyoming
*Ohio River Mainstem	Indiana, Illinois (IL), Ohio (OH), Kentucky (KY), West Virginia (WV)
Green	KY
Kentucky	KY
Penobscott	Maine
Susquehanna	Maryland, New York (NY), Pennsylvania (PA)
Merrimack	MA, NH
River basin	**State(s)**
Upper Mississippi Mainstem	MO, IL, Iowa, Wisconsin, (WI), Minnesota
Flathead	Montana
Walker	Nevada, CA
Black	NY
Moose	NY
Muskingum	OH
Deschutes	OR
Rogue	OR
Williamette	OR
Alleghany	PA, NY
Beaver	PA, OH
Lehigh	PA
Monongahela	PA, MD, WV
Schuylkill	PA
Cowlitz	WA
Dungeness	WA
Fraser	WA
Hamma Hamma	WA
Hoh	WA
Hood	WA
Jorsted Creek	WA
Kalama	WA
Lewis	WA
*Nooksack	WA
Quinalt	WA
Salmon Creek	WA
*Skagit	WA
Snohomish	WA
Spokane	WA, ID
Stillaguamish	WA
Wenatchee	WA
White	WA
*Yakima	WA

* Hydropower projects in these river basins have not undergone all required NEPA analysis.

comments about potential cumulative impacts of three license applications and one exemption on important environmental resources in the Hamma Hamma River Basin.

A supplemental draft EIS was completed for the Hamma Hamma Project in November 1986 (Federal Energy Regulatory Commission, 1986b). This supplemental EIS dis not contain a lengthy description of the existing environment because it had already been described in the draft EIS. The supplemental draft EIS took about 1 year to complete with the assistance of the Argonne National Laboratory.

The staff determined in this supplemental draft EIS that there would be significant cumulative adverse impacts to important resources in the Hamma Hamma River Basin. After the supplemental draft was completed, the applicant for the Hamma Hamma Project withdrew the application for the project. The supplemental draft EIS provided the information needed to evaluate the three other projects in the basin. No final EIS was ever prepared.

Cumulative Environmental Assessments

The EA-approach to determining cumulative impacts associated with multiple hydropower development in river basins is the method most frequently used by the staff. This method is most familiar to people involved in writing and reviewing NEPA documents and provides a flexible and timely approach to reaching conclusions on whether a project would significantly affect the quality of the human environment.

The staff completed the first EA evaluating the cumulative impacts of multiple hydropower projects in May 1984 (Federal Energy Regulatory Commission, 1985c) and completed two more cumulative EA's in July 1986 (Federal Energy Regulatory Commission, 1986c, 1986d). These three EA's examined clusters of hydropower projects in the Upper San Joaquin and South Fork of the American River Basins of California, and evaluated a total of 20 projects. Two of these cumulative EA's were drawn from background information contained in EIS's already prepared for other individual projects in the same river basins. The development and completion of other cumulative EA's followed, and by August 1986, the Commission published notices in the Federal Register requesting public comments on cumulative environmental impacts from hydropower projects proposed in the Pit and Kings River Basins, California, the Rogue and Willamette River Basins, Oregon, and the Lehigh River Basin, Pennsylvania.

Most of the early cumulative EA's were written on the premise that two or more hydropower projects must be proposed for a river basin in order to cause cumulative impacts. The acceptance in 1987 of the CEQ regulations on cumulative impacts changes the staff's earlier perspective that two or more projects were needed in a basin before a cumulative assessment could be performed. Under the new CEQ guidelines, the staff evaluates the potential cumulative impacts of any one pending application for a project in a basin with other "past, present and reasonably forseeable future actions regardless of what agency or person undertakes such other actions." The staff recognizes that cumulative impacts can result from individually minor but collectively significant actions, taking place over a period of time. A single proposed hydropower project in a river basin, for example, may cause cumulative impacts on the environment when considered with other uses such as logging, irrigation, or rapid commercial development occurring in some other part of the basin.

In the past, cumulative EA's were separate documents, used in conjunction with other staff-generated NEPA documents to determine the significance of environmental impacts caused by proposed projects and to decide whether a project should be licensed. The Commission decided to issue public notices in the Federal Register on a case-by-case basis.

The present trend, already underway, is to have the cumulative assessments combined with the site-specific analysis and made a part of each NEPA document (usually an EA) prepared for a hydropower application. All EA's prepared by the staff are now noticed in the Federal Register.

Summary

The staff has learned a great deal from the use of different approaches developed for cumulative impact assessments associated with hydropower development in river basins. The Commission's experience with cumulative impact assessments reflects the uncertainties and complexities of the process, but will provide direction for future cumulative impact analyses. Ultimately, the public, state and federal resource agencies, and developers will benefit from the lessons learned, and will be one step closer to identifying and accepting methodologies for cumulative impact assessment. The knowledge gained from cumulative impact assessments can lead to better-informed decisionmaking by the Commission and can offer more protection to the environment through improvements in designing hydropower projects that are more compatible with the surrounding environment.

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SESSION 10:

ENVIRONMENTAL MITIGATION

Chairperson: J. Hamilton
Ministry of Natural Resources

Studies of Fish Protection Methods at Hydroelectric Plants

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STUDY OF FISH PROTECTION METHODS AT HYDROELECTRIC PLANTS

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ABSTRACT

Protecting fish from entering hydraulic turbines has become an important objective of both regulators and utilities. Current and future hydro plant relicensing efforts have increased the need to develop and evaluate cost-effective methods for protecting anadromous fish from turbine mortality. Accordingly, in 1985 the Electric Power Research Institute (EPRI) initiated studies to evaluate the status of existing fish protection technologies, identify the research and development needed to improve the effectiveness and reduce costs of these technologies, and to identify the effectiveness of several concepts which showed promise but had not been fully evaluated.

In 1986, the first phase of the EPRI study was completed and results were presented in a detailed report (EPRI 1986). From the Phase 1 assessment it was clear that no single system existed which was biologically effective, operationally reliable, economically feasible and acceptable to regulatory agencies. Therefore, it was recommended that five largely untested and economical protection systems be tested at sites throughout North America.

At the end of 1986, the process of selecting laboratory and field test sites was completed. Studies were completed in 1987. The sites selected (and the type of systems evaluated) include: the Hadley Falls/Holyoke complex on the Connecticut River (mercury light/spill; mercury light/bypass pipe; strobe light; sound); the Ludington Pumped Storage Project on Lake Michigan (mercury lights, strobe lights and sound); the Wapatox Canal on the Naches River in Washington (mercury light/screen and bypass); and Wanapum Dam on the Columbia River (mercury light/spill). In addition, laboratory studies of basic behavioral responses of fish to mercury and strobe lights were conducted by the Universities of Iowa and

Washington. Similar studies were conducted with a sound generating device (hammer) by Ontario Hydro. This paper will present the results of all studies.

INTRODUCTION

Protecting fish from entering hydraulic turbines has become an important objective of both regulators and utilities. In 1986, the Electric Power Research Institute (EPRI) funded an in-depth evaluation of available technologies for protecting downstream migrating fish, as well as resident fish, at hydroelectric facilities. Results of this study are presented in an EPRI report entitled "Assessment of Downstream Migrant Fish Protection Technologies for Hydroelectric Application" (1). The report concludes that, despite many years of research, no single system exists today that is biologically effective, operationally reliable, economically feasible, and acceptable to regulatory agencies. In part, this situation results from stricter goals recently imposed by some agencies seeking a high degree of protection at sites affected by rapid increases in hydropower development, existing mortality problems, or fisheries restoration programs.

This situation has caused serious problems for utilities and regulatory agencies and continues to affect the hydroelectric licensing process. Recently promulgated regulations allow fishery agencies in the United States a greater role in the licensing/relicensing process. Increasingly, these agencies are requesting that fish protection measures be applied at hydroelectric projects. In some cases, the need for protection has not been demonstrated or is apparently lacking. Even where there is a clear need for protection, utilities and developers have little to draw on in terms of available fish protection technologies that they might apply to their projects. The application of fish protection systems at many hydroelectric plants today carries risks for the owner, the agencies and, most importantly, to the fisheries resources at potential risk.

The following discussion addresses the question of when fish protection is needed, identifies what protection technologies are currently available, summarizes the results of all recent EPRI testing, and offers suggestions on what courses of action might be taken in future licensing efforts to address the issue of fish protection.

ESTABLISHING THE NEED FOR FISH PROTECTION

A major issue in the licensing of hydro projects has been the need for fish protection. Until relatively recently, most fish protection research at hydroelectric facilities centered on preventing turbine mortality of salmonid outmigrants at large dams in the Pacific northwest and in Canada. The passage of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the "oil crisis" of the early 1970's resulted in a rapid increase in the number of proposed hydro projects throughout the United States. This rapid growth raised concerns among the Federal Energy Regulatory Commission (FERC) and state, regional and national fisheries agencies over potential fish losses resulting from development of a large number of projects throughout the country in a short period of time.

Many of these projects are proposed for environments supporting a wide variety of non-anadromous fish species which are considered to be "resident." In addition, many projects are located on rivers undergoing or slated for restoration of runs of anadromous species not previously encountered at hydro projects. Where there are no existing anadromous fish populations, or where populations are resident, there is often little biological data on which to determine potential impacts of hydro development at proposed sites. From a fish protection viewpoint, licensing of these projects is a difficult process for all involved.

At some sites where there is a lack of biological information, some developers have quickly implemented baseline fisheries investigations and turbine mortality studies in an effort to quantify potential impacts. These studies are often required after initial consultation with the agencies. Unfortunately, most of these studies have failed to convince the regulatory agencies that protection measures are not needed. In particular, the extreme difficulty of conducting turbine mortality studies has resulted in data which is limited, equivocal and often highly contested. Likewise, data on species occurrence and population structure have not provided an indication of the numbers of non-requisite migratory (i.e.., "resident") species which might be subject to "entrainment and impingement" at hydro projects with or without fish protection systems.

With a lack of information to direct the fisheries resource agencies otherwise, it is usually assumed that "entrainment and impingement" are problems and that there is a need to provide protective measures. Therefore, even though the need for a fish protection system is seldom well-defined, the recommendations of the fisheries agencies conservatively assume that such a system is needed. The incremental cost of a fish protection system at a hydro plant can affect the economic viability of that project.

This situation will arise repeatedly as hundreds of existing hydroprojects come due for relicensing over the next decade. While most of these projects have been in operation for many years, the relicensing process permits the fisheries agencies and FERC to impose requirements for fish protection. In particular, the Electric Consumers Protection Act of 1986 gives the fisheries agencies the right to review all license applications and to recommend to FERC mitigative measures that are deemed necessary to offset existing or potential project impacts on fisheries resources. Once again, the issue of the need for protection is, and will continue to be, a prominent one in the licensing of most existing and proposed projects.

Even where a reasonable need for fish protection can be established, the current ability to address that need is limited. As stated previously the 1986 EPRI report concluded that no single system or device currently exists which is biologically effective, operationally reliable, economically viable and is accepted by the regulatory agencies. This situation presents a dilemma for both agencies and developers. While the agencies have the power to require fish protection and the developer may be willing to install reasonable measures, fish protection measures do not exist which can be generally applied with assurance that they will be effective. However, as described below, ongoing research may result in the identification of one or more devices or systems which will offer the potential for protecting fish at both steam electric and hydroelectric projects.

CURRENT RESEARCH EFFORTS

Current research is directed at developing and/or optimizing the design of a number of protection devices or systems. The status of each system or device is presented briefly below.

Submerged Traveling Screens - These screens are inserted into gatewell slots to intercept fish entering the turbine intake of hydro plants and direct them to a bypass. Submerged screens have been installed and tested at a fair number of large projects in the Pacific northwest. To date, the effectiveness of the screens has been variable. The screens appear to have the potential for good efficiency if site-specific problems can be resolved. Not all fish are screened by this system since the submerged screen extends only part way into the water column. Further, screen contact with resultant scale loss has occurred to varying degrees. Bypasses have not always performed adequately, and debris accumulation and insufficient bypass flow have been major problems. While many of the operating problems associated with submerged screens have been resolved, others still exist which need to be resolved.

Angled Screens - Angled screens have proven effective in diverting a wide variety of warm- and cold-water fishes to bypasses. At hydro facilities, the screens are typically panels which can be removed or backwashed for debris removal.

With further testing and engineering refinement, angled screens could prove to be one of the most effective fish protection systems available. The primary engineering concern with stationary screens is debris clogging; therefore, priority should be placed on developing an effective and reliable debris removal system.

Bar Racks - While coarse bar racks are a standard feature on many hydropower projects, closely-spaced racks designed to block fish passage have not been extensively studied. Bar racks with 1 to 3 inch spacings have been shown to cause avoidance of downstream migrants. At a number of projects, bar racks combined with small bypasses have been shown to effectively reduce turbine passage. Given the proper location, orientation and hydraulic conditions, bar racks should prevent passage of larger fish through physical exclusion and smaller fish through behavioral avoidance. Research is warranted to better identify the effectiveness of this cost-effective protection system.

Angled Bar Racks - Angled bar racks have been used on a small number of small-scale hydro plants in New England. There has been a recent interest expressed by several fisheries agencies to apply angled racks to large-scale projects as a regional approach to the issue of preventing turbine passage. To date, there are little data to indicate that such application would be effective. While an angled bar rack might be developed which acts as a fish diversion device, hydraulic model studies and detailed design development, followed by field verification studies, are needed to establish design criteria and optimum layouts and hydraulic conditions.

Angled Drum Screens - A number of large- and small-scale drum screens will come into operation in the next decade. Several are already in operation. These systems have been designed to incorporate the most current features for ensuring optimum fish guidance and survival. Hydraulic model studies have been conducted to verify optimal hydraulic conditions. Detailed biological studies have conducted at least one installation; results from this site are encouraging. One constraint in the use of angled drum screens is the requirement for relatively constant water depth.

Inclined Plane Screens - Like the angled screen, inclined plane screens appear to have the potential for being an effective system for protecting fish. From the two small-scale facilities presently in operation, biological and engineering information are being gathered which should result in the identification of design and operating criteria to optimize system effectiveness for the species present. To date, the screen has only been evaluated with salmonid outmigrants. Further, there has been a reluctance on the part of some agencies to accept the design due to the relatively high velocities used and the limited and small-scale testing conducted to date. Therefore, further development of the inclined plane screen should be carried out with continued input from appropriate fisheries agencies.

Fixed Screens - Fixed screens have been installed at a variety of small-scale hydroelectric facilities to protect salmonid outmigrants. The primary concern with using fixed screens is the potential for clogging. Moving brush and wiper systems presently exist which appear to be effective in removing relatively light debris loads. Additional research is warranted to improve existing screen designs, identify the potential for wider application, and determine the size (flow rate) at which fixed screens are no longer cost-effective.

Behavioral Barriers

Behavioral barriers have been used to attract and repel fish with variable success. EPRI is presently sponsoring field evaluations of three barriers:

- strobe lights for repelling fish
- mercury lights for attracting fish
- a sound generating device known as a "hammer" for repelling fish

In 1987, studies were conducted at four test sites located across the United States:

- the Hadley Falls/Holyoke complex (located on the Connecticut River, Massachusetts)
- the Ludington Pumped Storage Project (located on Lake Michigan, Michigan)
- the Wapatox Canal (located on the Naches River, Washington)
- Wanapum Dam (located on the Columbia River, Washington)

In addition to the field sites, laboratory research was conducted to determine the basic behavioral responses of selected species to the three test devices. Laboratory research sites included the Universities of Washington and Iowa and Ontario Hydro.

The studies were conducted between April and November of 1987. Results from each site are presented below.

Hadley Falls/Holyoke - The purpose of the studies at this site was to evaluate the effectiveness of strobe lights, mercury lights and hammers in modifying behavioral responses of adult and juvenile American shad at several downstream passage facilities (Figure 1). The goal was to determine whether some or all of the devices modify fish behavior and enhance downstream movement while minimizing mortality.

For adult shad, strobe lights and mercury lights were tested at two locations. Fish entering the Holyoke Canal system can follow one of two passage routes: 1) directly downstream to the Boatlock Hydro Station which incorporates a fish bypass and return pipe to the river or 2) down a branch canal in which the fish become trapped. Therefore, it would be desirable to prevent fish passage into the branch canal (First Level Canal; Figure 1) and enhance fish movement to the Boatlock Station bypass. Strobe lights were placed in an array across the branch canal at the Lyman Street bridge to repel fish back upstream toward Boatlock. At Boatlock, above-water and underwater mercury lights were installed to attract fish to the bypass. Studies with adult shad were conducted in June.

Juvenile shad move downstream past Holyoke in the fall. To prevent their movement into the turbines at Hadley Fall Station, mercury attraction lights were placed on either side of the plant intake. On one side, the fish were attracted to a bascule gate which spills to the tailrace. On the other side, the fish were attracted to the exit to the fishway used for passing adults upstream.

Juvenile shad also pass into the canal system during their fall outmigration. As with adult shad, these fish must pass through the Boatlock Station bypass for quick and safe return to the river. Therefore, the strobe lights in the branch canal and the mercury lights at Boatlock Station were tested with juveniles in the fall. In addition, an array of five hammers were positioned across the branch canal adjacent to the strobe lights to evaluate the potential effectiveness of sound in repelling fish.

Results of spring testing with adult American shad were conducted over a two week period of time. Two weeks of strobe light data were obtained in the branch canal and one week of mercury light testing was conducted with mercury lights at the Boatlock Station bypass.

Results of strobe light testing demonstrated that the lights had no effect on the behavior of adult shad under any condition during the entire test period. This result was not unexpected since the shad move primarily during daylight hours when the light level created by the strobes is incidental to solar insolation, even on days of heavy cloud cover. It was thought that fish might react to the point source of the light and avoid it. For adult shad, this reaction was noticeably lacking.

At Boatlock Station, the data indicate that the mercury light had no effect on the passage of adult shad during the day. At night, however, over twice as many fish were bypassed when the light was on. The results indicate a positive relationship between light condition and fish bypass rate.

Fall testing of strobe light, mercury light and hammers with juvenile shad was limited by a series of unusual high water events during outmigration. Juvenile outmigration density was much lower and variable than anticipated. Differences between test devices were not significant.

Ludington Pumped Storage Plant - The purpose of the studies at Ludington was to obtain preliminary information on the behavioral response of a variety of indigenous and introduced lake fish to lights and sound. The large size of the forebay necessitated establishment of a "test zone" within the embayment in which mercury lights, strobe lights and hammers could be tested (Figure 2). The optimal location for this zone was identified on the basis of known hydraulic conditions, a preliminary hydroacoustic survey of the entire forebay, and weather considerations.

A boat moored in the forebay served as a work platform (Figure 2). The boat was secured on either side to piles and by mooring blocks fore and aft. The piles were also used to mount the strobe lights, hammers and acoustical transducers. Mercury lights were mounted on poles which were lowered into the water and secured on either side of the boat for testing. Four strobe lights were used to achieve the desired level of illumination. Two mercury lights and two hammers were set at mid-depth on each pile.

The effectiveness of the strobe lights and hammers in repelling fish and mercury lights in attracting fish was monitored using hydroacoustic techniques combined with net sampling. Tests were conducted with the lights and hammers operating separately and under ambient (no lights or hammer) conditions. Testing was conducted during nighttime periods of pumping only. Each test lasted for 2 hours; attempts were made to conduct four tests per night. Since the occurrence and abundance of fish varied over the period of study and within a sampling day, the sequence of sampling the test devices and the control was varied from night to night. Tests were conducted 12 consecutive nights per month for 5 months (June to October).

From June to November, testing occurred over a 2-week period each month. Strobe light, mercury light, hammer and control tests were conducted sequentially each night. The order of each test condition was varied such that each device was tested several times at each time period during the night to account for variability in fish occurrence and abundance over time. Results of the data analysis show that the number of fish in the test area was significantly greater with mercury lights operating than under the control condition. Fish abundance varied from month to month but abundance was usually about two times greater with the mercury lights than under ambient conditions. Visual observations verified a strong attraction to the lights. Generally fish abundance under hammer and strobe test conditions were less than that under ambient conditions. However, operating the strobe lights and hammers did not significantly reduce fish abundance in the test area relative to the control.

Wapatox Canal - The purpose of the studies at Wapatox was to determine whether mercury lights can be used to improve the rate of fish passage and the effectiveness of existing drum screens in diverting fish from the canal to the river. The canal is about 70 feet wide and contains six, 6.5-ft diameter rotary drum screens set perpendicular to the flow (Figure 3). Vertical slot bypasses are located at each side of the canal. The combined bypass flow transports fish via pipeline to a discharge point 1200 ft downstream of the canal entrance.

To enhance fish passage into the bypass, mercury lights were placed at one bypass entrance shining upstream and in the bypass well into which the bypass slots discharge. The other bypass was screened. The first test series was run from March 31 to June 11. Tests were conducted on eleven nights during this period. The predominant species collected were chinook and coho salmon fingerlings and rainbow trout fingerlings. Tests were conducted from early evening to late night and lasted from 4 to 8 hours, depending on fish abundance. During each test, the lights were sequenced on and off on a regular half-hour or hourly basis. Fish were removed from the bypass trap shortly after a change from one light condition to the other and again at the completion of each test.

This test series provided direct evidence that fish were attracted to the mercury light, but the rate of fish passage was not substantially different between light and dark conditions. However, a very evident increase in passage rate did occur each time the lighting condition was changed. It appeared that the fish were reluctant to pass into the area of highest light intensity. Over the spring test period, a number of changes were made and evaluated to reduce avoidance and take advantage of the increase in fish passage during transition periods. First, the mercury light at the bypass entrance was moved laterally to a point 11 ft away from the bypass, as shown on Figure 3. Next, the light in the bypass well was reoriented such that only backscattered light was illuminating the bypass entrances. Finally, a third light was placed in the fish transport pipe immediately downstream of the well.

In the 1-week fall test series, the revised lighting arrangement was evaluated. The light intensity was also decreased to the lowest setting possible, roughly 50 percent of full intensity. The primary test species was hatchery-reared, fingerling chinook salmon which were marked and released in groups each night. During the first night, the lights were on for 4 hours (1930-2330) and off for 4 hours (2330-0330). As in the spring, there was a rise in fish passage rate during the light-to-dark transition period; however, as before, there was no evident difference in rate between on and off conditions that could be attributed to the lights. Therefore, in subsequent tests, the lights were turned off for 5 minutes each hour during the "light on" test period. The intent of this approach was to "pulse" fish through the system on a periodic basis. Combining all data, nearly two times as many fish were bypassed with the lights on (863 fish) than with the lights off (451 fish).

Pulsing the light had an obvious positive effect on passage rate. With the chinook fingerlings, the pattern of passage rate from early to late evening was reversed from on night to the next as the on:off sequence was reversed. For example, on September 23, the number of fish passed with the on:off sequence was 220:26. The low number during the off period reflects a natural diel pattern of reduced movement after about 2300 hours. The next night the sequence was reversed and the off:on numbers reversed to 78:115. These data indicate a strong effect of the light at all times.

The light's effect was particularly pronounced with wild kokanee which entered the canal naturally. As shown on Figures 4 and 5, there was a dramatic reversal in passage rate and total number of fish passed when the light sequence was reversed over two consecutive nights. These results indicate a strong positive effect of mercury lights on at least two of the species collected at Wapatox.

Wanapum Dam - The purpose of studies at Wanapum was to determine whether mercury light can be used as an attractant to increase fish passage through the spillways while decreasing turbine passage (Figure 6). Lights were installed on both sides of one spill (Number 9).

The lights were not operated during the first seven days of spill. During this time, hydroacoustic data was recorded which provided baseline data for control purposes. After this control period, the lights were tested in a paired design within each test day. The lights were tested every night with the ON/OFF sequence alternated from one night to the next. On a given night, the test lights were on and off for equal lengths of time (5 hours) over the period that fish were actively migrating (10 hours). The sequence of sampling was such that an approximately equal number of tests was conducted with each ON/OFF sequence over 29 days of the outmigration period at Wanapum.

Hydroacoustic data were obtained from tranducers located on the spillways at Wanapum Dam. Figure 7 shows the number of fish passed through Gate 9 (the lighted gate) over the 29 sampling days. Each day, there was a 2-hour (1800-2000) pre-test period (designated as "P"). Tests were then conducted over two, 5-hour periods (2000-0100 and 0100-0600) with the lights either on ("Y") or off ("N"). The on:off sequence was alternated from night to night. Figure 7 shows great variability in fish passage from day to day. This variability in fish passage was evident for all six spill gates.

Figure 8 shows fish passage over time of night by light condition, i.e. total number over all dates by hour and light condition. The figure shows that peak fish passage occurred over relatively few hours. The same trend was evident for all spill gates.

The figures show no obvious differences in passage rate during lighted and unlighted periods. The short outmigration period, in terms of both dates and time of day, makes evaluation of possible increases in fish passage rate due to lights difficult.

Universities of Iowa and Washington - The purpose of the laboratory studies at these two sites was to determine the basic behavioral responses of a variety of species to strobe lights and mercury lights. Similar test methods were employed at both sites. Each species and light was tested individually in test flumes under static flow conditions. For each test, a group of test fish was placed in the flume and allowed to acclimated to ambient conditions. Following the acclimation period, a light (mercury or strobe) was activated at one end of the flume and fish response was recorded by video camera. At the end of a 30-minute period, the light was turned off and the same type of light located on the other end of the flume was turned on for 30 minutes. At the completion of each pair of tests, the test group was removed and a new test group was used for the next paired test.

At the University of Washington, coho, chinook, and Atlantic salmon and steelhead trout showed an avoidance to strobe lights in the test flume. Coho salmon showed the strongest avoidance. The data indicate that boundary effects in the flume may have affected the fishes avoidance response, since there were no dark areas to which the fish could escape. It is possible that even stronger avoidance would have been noted if the fish had such an escape area.

Coho, chinook and Atlantic salmon smolts showed little reaction to the mercury lights. Steelhead fry, on the other hand, displayed a strong and consistent attraction to mercury lights which increased over time of exposure. These data indicate that there are species-and life-stage-dependent reactions to strobe and mercury lights.

Preliminary results from the University of Iowa indicate that response was very variable and may be due to high light intensity in a confined location. Juvenile catfish and bluegill showed little response to the strobe while juvenile hybrid bass appeared to avoid the strobe. Juvenile walleye moved back and forth in the test tank when exposed to the strobe. More complete results will be forthcoming shortly.

Ontario Hydro - The purpose of the laboratory studies at this site was to determine the basic behavioral response of fish to a hammer generating five different low-frequency sound spectra. Tests were conducted in a large, semi-anachoic test tank. Different frequencies were created through the action of a metal rod striking metal plates of different thicknesses. The intent was to identify the frequency that elicits the greatest avoidance response by each species.

Results of the hammer test demonstrate that hatchery-reared Atlantic and chinook salmon and rainbow trout do not respond to the hammer at any frequency. Adult alewives showed a response, but it was not as strong as that seen with juvenile alewives in previous studies by Ontario Hydro. As with the lights, it appears that the effectiveness of the hammer is species- and life-stage-dependent. There is also a preliminary indication that hatchery-reared and wild fish of the same species may react differently. These relationships require additional study.

FUTURE DIRECTION

There is an immediate need to develop protection systems for hydroelectric projects. In the next few years, the industry should not follow a short-term course of action requiring installation of fish protection measures which are largely experimental and unproven for the environments in which they are needed (whether the need is real or assumed). Instead, a concerted effort should be made by the industry and the agencies to continue research on promising devices and systems and to expand efforts, where necessary, to meet the requirements of a variety of environments. In this way, systems should evolve which will truly protect fish from mortality at water intake structures. Only after systems have been developed and tested can the cost-benefit of a particular system be addressed. Without quantitative information on both costs and effectiveness, the developer may expend large sums of money on a system and the agencies may not achieve their goal of minimizing impacts.

Naturally, this course of action presents an immediate problem for FERC and the fisheries agencies: what action should be taken with respect to fish protection at projects which are under license review now and in the near future? Several courses are possible, one which would be undesirable to developers and one which requires some risk to the agencies' position and a third which would require some risk to both parties.

The first approach would be similar to that taken by the agencies at present. For each site, the agencies would make a recommendation to FERC (based on available information) on the type of system the developer should be required to install to meet the perceived need for fish protection. The developer would then have to install the system or develop additional data to 1) determine that fish protection is not necessary or 2) that an alternative protection system would be more cost-effective. In this way, the developer is required to increase the amount of information on which the agencies can make more informed decisions. There are several drawbacks to this approach. First, it could cause significant delays in a project, with associated economic penalties. Second, it has not been possible in studies to date to generate the kind of data require to demonstrate that fish protection is not needed. The capability to obtain this type of information in the future is questionable. Finally, since there is no generally accepted fish protection system available, it is unlikely that developers could identify cost-effective alternative protection designs in the near term.

The second approach would be to issue licenses which have provisions requiring backfit of protection systems at a future date when valid protection alternatives have been identified. The developer might be given the option of conducting studies designed to identify whether there is a real need for protection at a site in an effort to avoid the delayed cost of installing a fish protection system in the future. This approach carries some risk for FERC and the agencies since the cost of the protection systems developed could become prohibitive as a backfit. Further, there is a risk that a project would have a significant impact on fish populations while studies are ongoing to identify impacts.

A solution to these problems would be to have a generic study conducted in which general design layouts and costs for potentially effective protection systems would be identified. The study would address fish protection on a regional or river basin basis. A number of layouts and costs would be developed for each alternative to reflect gross differences in plant designs and operating procedures. A study of this nature would allow the agencies and the developers to agree *a priori* on one or more systems that might be required for installation at a later time. This would allow the developer to conduct a worst-case cost analysis during initial project development and decide up front whether a potential fish protection measure would affect the economic viability of the project.

The final approach would be to delay licensing of projects which appear to have a high potential for "entrainment and impingement" until such time that a cost-effective protection system can be identified. This approach would have a severe economic impact on some projects and could result in the withdrawal of permit applications. However, it would achieve the goal of minimizing impacts.

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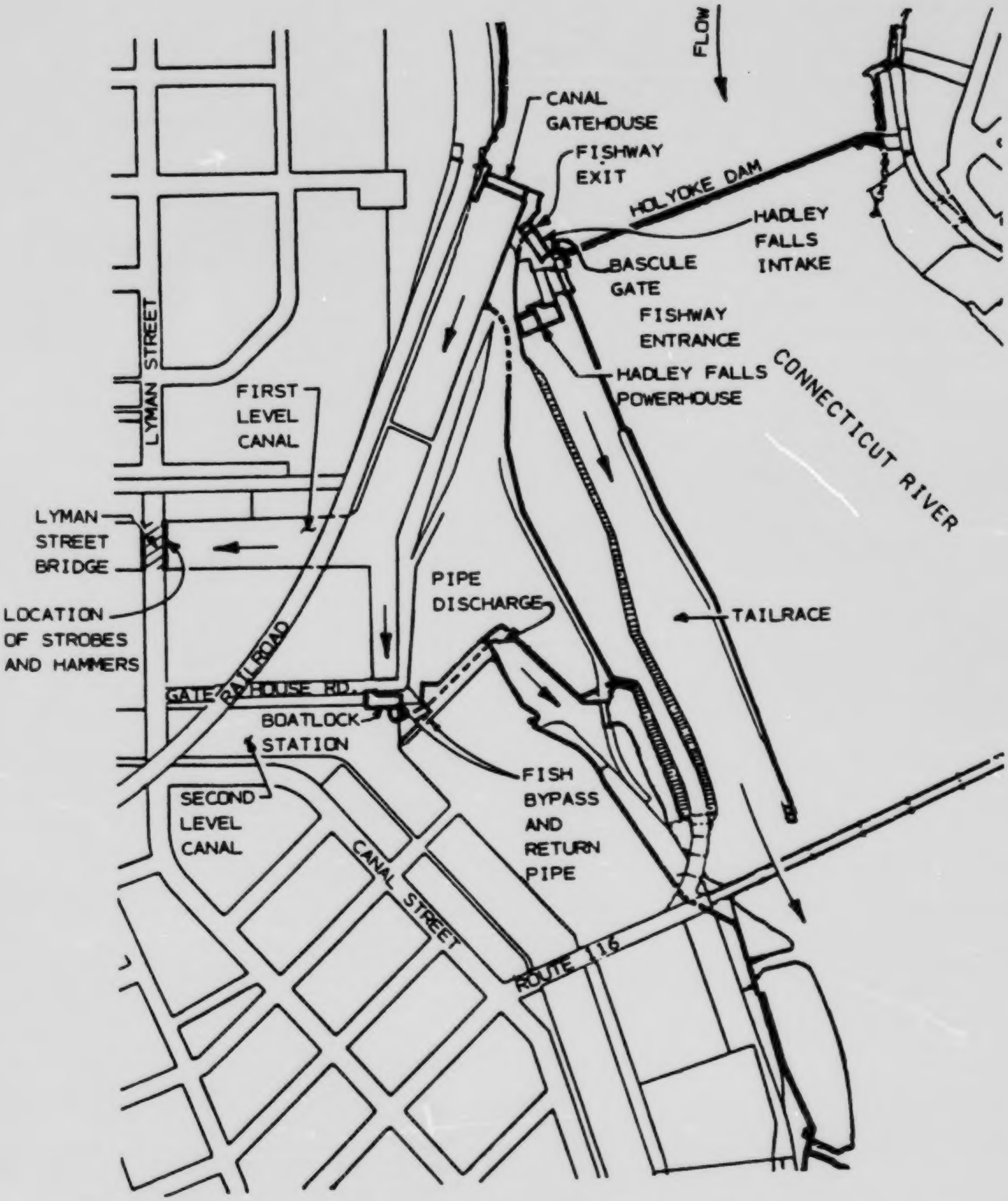

FLOW
CANAL GATEHOUSE
FISHWAY EXIT
HOLYOKE DAM
HADLEY FALLS INTAKE
BASCULE GATE
FISHWAY ENTRANCE
HADLEY FALLS POWERHOUSE
CONNECTICUT RIVER
LYMAN STREET
FIRST LEVEL CANAL
LYMAN STREET BRIDGE
LOCATION OF STROBES AND HAMMERS
PIPE DISCHARGE
TAILRACE
RAILROAD
GATE HOUSE RD.
BOATLOCK STATION
SECOND LEVEL CANAL
FISH BYPASS AND RETURN PIPE
CANAL STREET
ROUTE 116

Figure 1. Hadley Falls/Holyoke Test Site

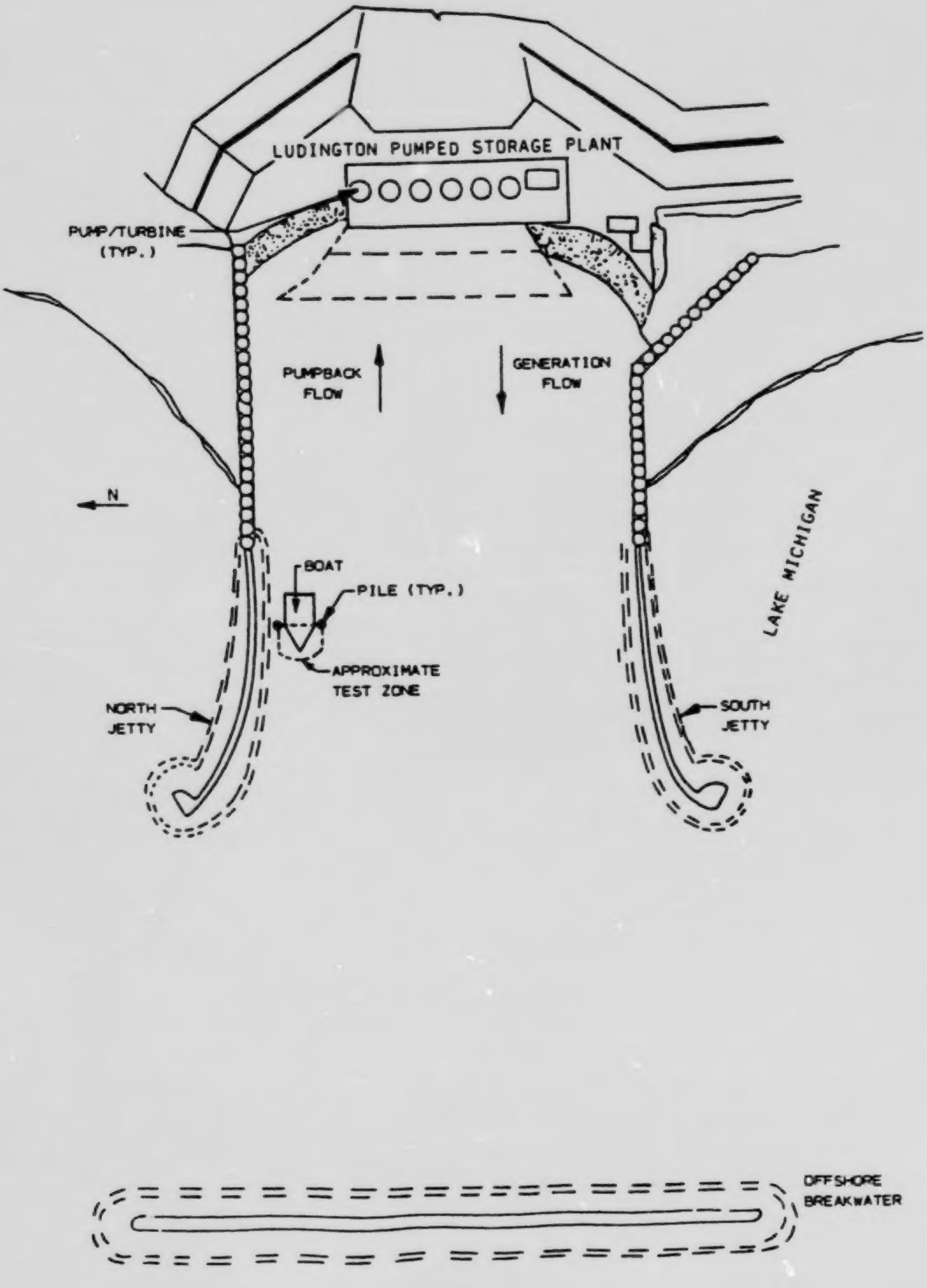

LUDINGTON PUMPED STORAGE PLANT
PUMP/TURBINE (TYP.)
PUMPBACK FLOW
GENERATION FLOW
N
LAKE MICHIGAN
BOAT
PILE (TYP.)
APPROXIMATE TEST ZONE
NORTH JETTY
SOUTH JETTY
OFFSHORE BREAKWATER

Figure 2. Ludington Pumped Storage Facility

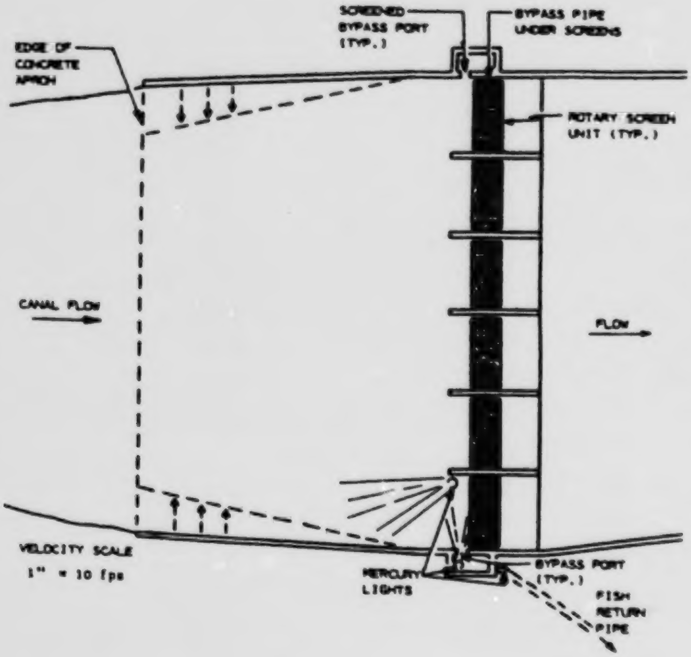
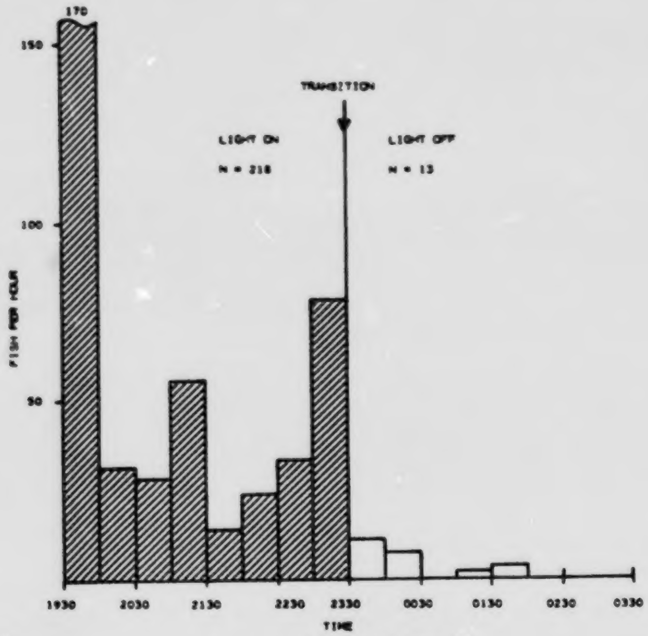
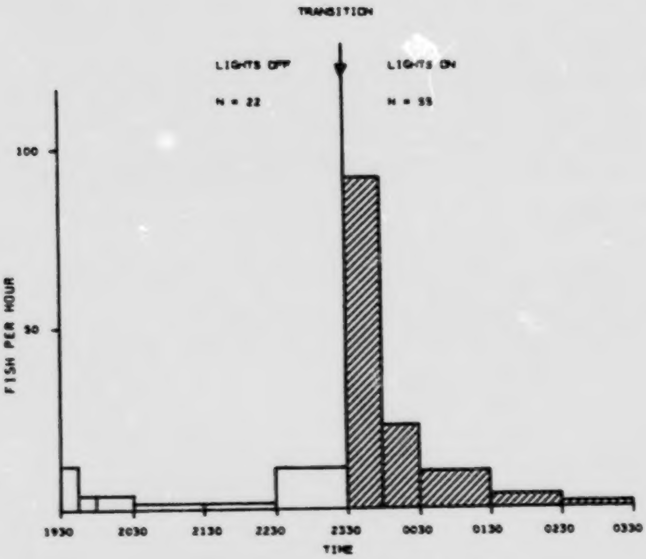

SCREENED BYPASS PORT (TYP.)
BYPASS PIPE UNDER SCREENS
EDGE OF CONCRETE APRON
ROTARY SCREEN UNIT (TYP.)
CANAL FLOW
FLOW
VELOCITY SCALE
1" = 10 fps
MERCURY LIGHTS
BYPASS PORT (TYP.)
FISH RETURN PIPE

Figure 3. Wapatox Canal Test Site



A. ON:OFF SEQUENCE



B. OFF:ON SEQUENCE

Figures 4 and 5 Results of Light Testing with Kokanee

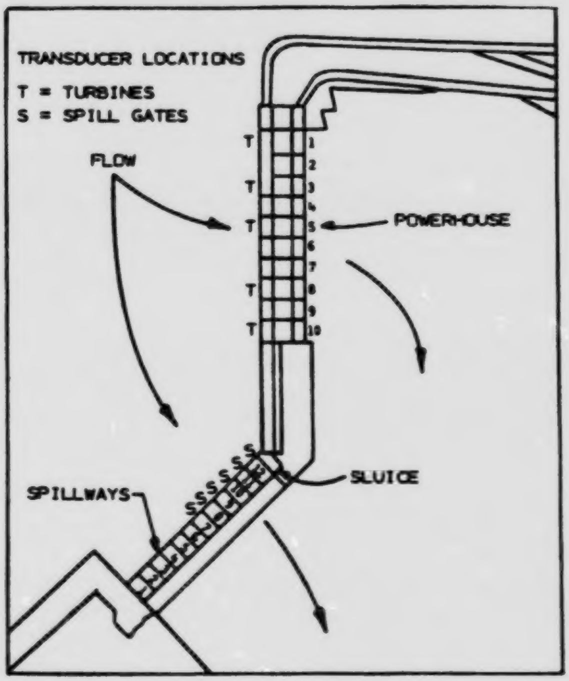

TRANSDUCER LOCATIONS
T = TURBINES
S = SPILL GATES
FLOW
T
T
T
T
T
1
2
3
4
5
6
7
8
9
10
POWERHOUSE
S
S
S
S
S
S
S
S
SLUICE
SPILLWAYS

Figure 6. Plan View of Wanapum Dam Showing Transducer Locations

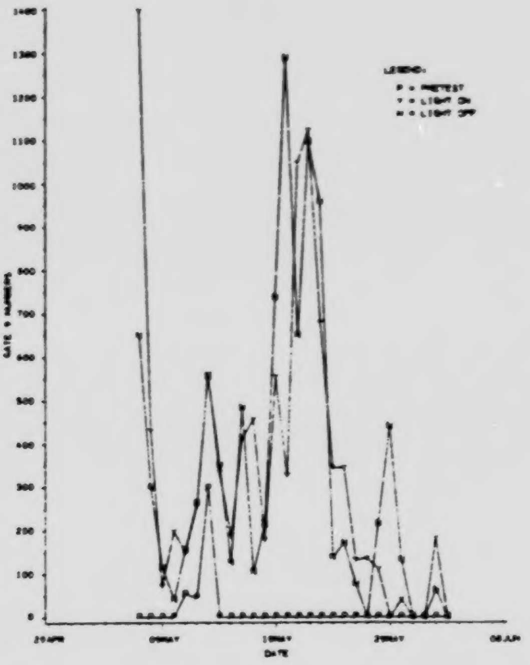


Figure 7. Number of Fish Passed through Gate 9 by Date and Light Condition - Wanapum Dam

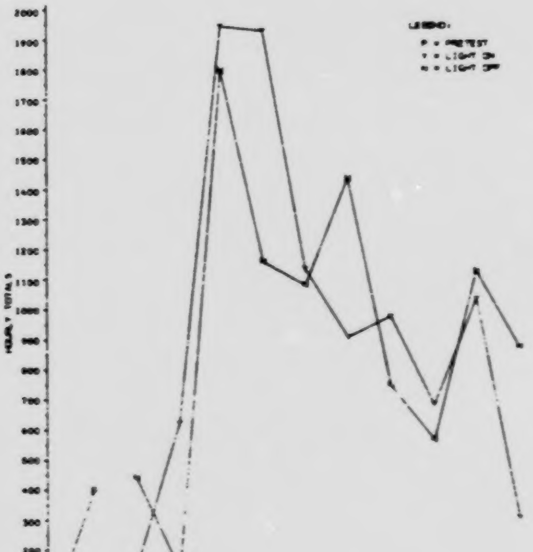


Figure 8. Number of Fish Passed through Gate 9 by Hour and Light Condition - Wanapum Dam

Trap and Transport:
Viable Passage for American Shad

By
T.D. Brush, D. Mathur, W.H. Bason

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TRAP AND TRANSPORT: VIABLE PASSAGE FOR AMERICAN SHAD

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Introduction

The passage of diadromous fishes at hydroelectric facilities has become one of the most important problems encountered in this industry. Many hydroelectric facilities impede the migration of adult and juvenile fish, thus reducing or eliminating the reproductive potential of a given population. Efforts to alleviate these problems are ongoing at many hydroelectric facilities.

A major capital cost for hydro facilities is the construction and maintenance of fish passage devices. Theoretically, providing passage for diadromous fishes allows completion of their life cycle. Unfortunately, fish passage devices are often not successful enough to allow a population to perpetuate itself.

Three basic types of upstream fish passage device exist: ladders, locks, and elevators (Clay, 1961). Conceptually, a fish ladder is the most desirable means of upstream passage for adults. Fish ladders require no handling of the fish and allegedly reduce delay in passing a dam as compared to other types of passage device. However, fish ladders are often exorbitantly expensive and not successful in passing a large proportion of a fish run (Mansueti and Kolb, 1953; Petts, 1984). The other two types of passage device lift the fish over the barrier: 1) by raising the downriver water elevation to equal that of the upstream reservoir (fish lock), or 2) by mechanically lifting the fish (fish elevator) in a large basket or hopper (Clay, 1961). Some degree of human intervention is needed in operating such devices, however they are generally much less expensive than fish ladders.

Each type of passage device has advantages and disadvantages, but no type passes 100% of a migrating population. Because of the inefficiency inherent in all fish passage devices, river systems with multiple dams pose a severe problem. A migrating population is reduced at each dam by a function of the passage efficiency of the device at that dam. This problem is especially detrimental to a population when no suitable spawning habitat exists between dams. Fish passage devices may actually reduce or eliminate a diadromous population in such a system. The objective of this paper is to tout the advantages of trap and transport of American shad (Alosa sapidissima) in a system with multiple dams by using the program in the Susquehanna River as an example.

Susquehanna River Shad Restoration

Goals and Limitations

Attempts to restore American shad, once an important commercial and sport fish, to the upper Susquehanna River have been underway for over 100 years (Mansueti and Kolb, 1953). The current goal of restoration is to establish a self-sustaining population of 2 - 3 million American shad by providing passage at each dam. Federal and state agencies, and the utilities that own the dams are responsible for the program. The dams are located at Conowingo, MD (rkm 16), Holtwood, PA (rkm 39), Safe Harbor, PA (rkm 52), and York Haven, PA (rkm 90) (Fig. 1).

Two facts hinder this program strategy. First, there is no significant amount of suitable spawning habitat between the first and fourth dams. It follows that a large proportion of the migrating population must successfully pass all four dams without signifcant delay to reproduce. Secondly, fish passage devices are inefficient at passing a large percentage (>80%) of a migrating population. Therefore, a significant proportion of the potential spawning stock will be lost at each dam. If all four passage devices were 80% efficient, only 41% of the potential spawning stock would reach suitable spawning habitat above the four dams; at 50% passage efficiency only six percent would reach the upper river. Additionally, the goal of 2 - 3 million American shad is not realistic, given present constraints, at passage rates of less than 80% - 90% at each dam (Brush et al., manuscript).

Trap and Transport

Trap and transport of diadromous fishes can alleviate the problem of inefficient fish passage devices in multiple dam river systems. Trap and transport from the first dam can greatly compensate for passage losses (inefficiency) at upriver dams by bypassing these facilities. The program may be limited only by the efficiency of the fish passage device at the first dam, not by the multiplicative effect of inefficient passage devices at all the dams.

A fish elevator at Conowingo Dam has been in operation during the spring run of American shad since 1972. There are no fish passage devices at any of the three upriver dams. American shad are lifted from the tailrace and loaded into tank trucks for transport upriver to suitable spawning areas. One thousand gallon circular fiberglass tanks mounted on 10' flat bed trucks are used to transport fish. The trucks are equipped with an oxygenation system and two 3 horsepower pumps for circulating the water in the tank. Oxygenation of the water and a circular flow for orientation of the fish are necessary for transporting large numbers of fish. A typical transport trip from Conowingo Dam, using the present equipment, carries from 200 - 300 adult American shad. It is preferable to maximize the number of fish per transport for economic reasons, and so that schools and spawning groups are more readily formed.

The number of American shad that can be transported is limited by the number of transport units available for use, and the operation time of the elevator. Transport vehicles may include trucks, train cars, or barges. In the Susquehanna River program, with six 1,000 gallon capacity tank trucks we estimate that 6,000 American shad can be transported upriver each day. The time between when a shad enters the fish elevator and is released in spawning habitat is often less than if the shad had access to a free-flowing river (i.e., minimum of 2 hours). Even if shad are held in tanks for one or two nights until a sufficient number are available for transport, the delay is likely less than would occur if the shad had to pass through each reservoir on its own.

The trap and transport effort has been successful in moving pre-spawned American shad in the Susquehanna River with nearly 17,000 fish transported since 1985. Survival over the last four years has averaged 97.5%. Transport time to the current stocking location is approximately two hours, however the present equipment is capable of making trips lasting several hours longer.

Downstream passage of fish may also be a problem in many river systems. Trap and transport of fish downriver is a viable means of bypassing dams (Trefethen, 1972) if collection of downstream migrants is feasible. As in upstream passage, there is a multiplicative effect when more than one dam is present. Bypass facilities or spills over the dam are usually more costly alternatives to trap and transport.

Conclusion

Maximizing the number of successful spawners on the spawning grounds is essential for a population to grow. The method of trap and transport for American shad (or other species) is especially suitable when dealing with a founder population, or a small population in a river system with more than one dam. A larger proportion of the potential spawning population can reach spawning habitat much less expensively by building a collection facility at the lowest dam on the river system (and highest, if downstream transport is desired) and transporting them around all barriers. Cooperative efforts between owners of all barrier dams and regulatory agencies, in a trap and transport program, may ease the costs of providing passage to diadromous fishes by eliminating the need for passage devices at all dams.

Acknowledgements

We would like to thank the Philadelphia Electric Company, particularly William F. McElroy, Howard F. Hansell, and the employees at the Conowingo Hydroelectric Station, for playing a key role in the American shad restoration program in the Susquehanna River, and for their support in making this presentation and paper possible.

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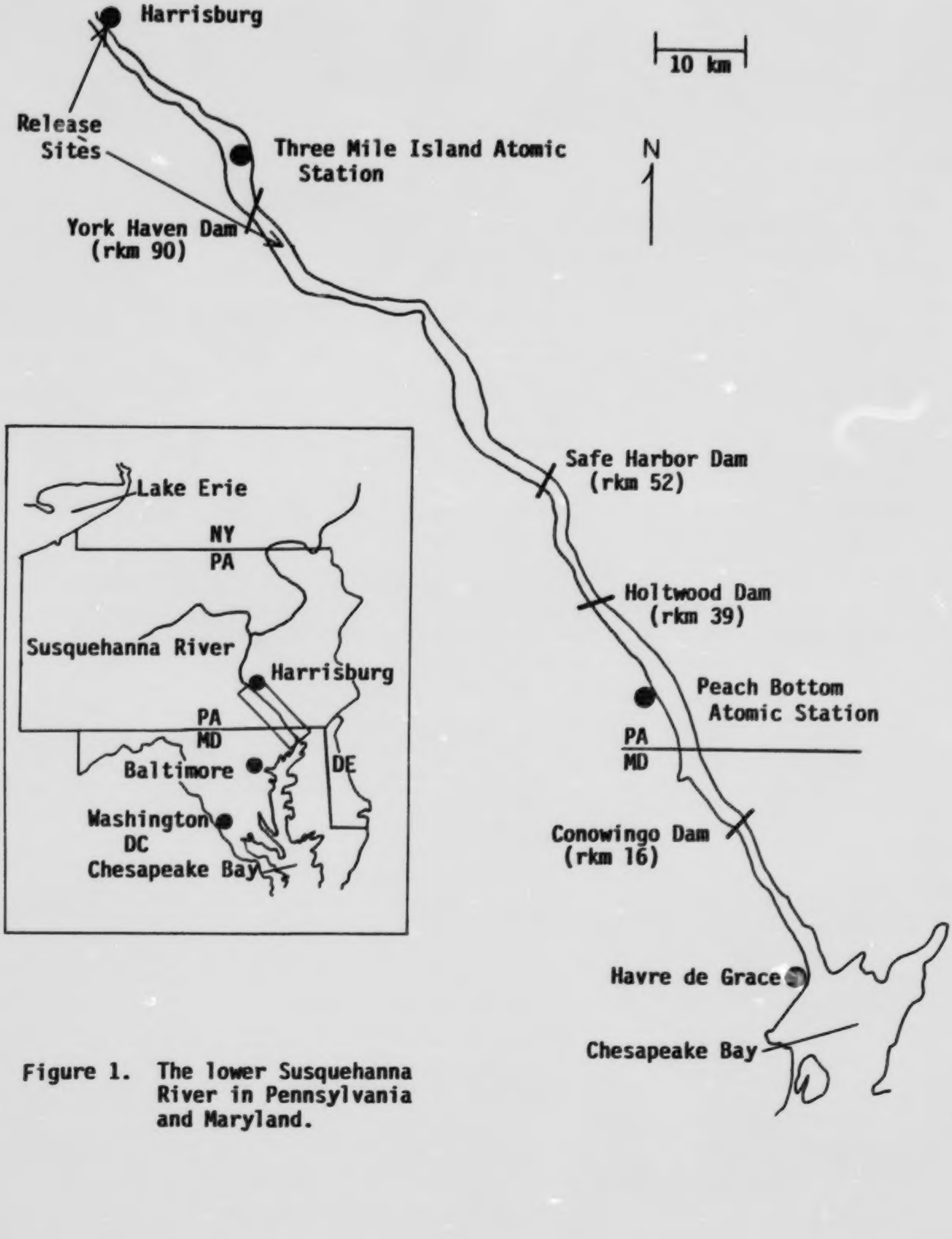
Harrisburg
10 km
Release Sites
Three Mile Island Atomic Station
N
York Haven Dam (rkm 90)
Lake Erie
NY
PA
Susquehanna River
Harrisburg
PA
MD
Baltimore
DE
Washington DC
Chesapeake Bay
Safe Harbor Dam (rkm 52)
Holtwood Dam (rkm 39)
Peach Bottom Atomic Station
PA
MD
Conowingo Dam (rkm 16)
Havre de Grace
Chesapeake Bay

Figure 1. The lower Susquehanna River in Pennsylvania and Maryland.

Development of Radio Tags
to Track Juvenile American Shad
at Hydroelectric Stations

By
D.D. Royer, P.G. Heisey, D. Mathur, B. Hanson

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DEVELOPMENT OF RADIO TAGS TO TRACK JUVENILE AMERICAN SHAD AT HYDROELECTRIC STATIONS

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INTRODUCTION

A suitable method to study turbine passage of emigrating juvenile American shad, Alosa sapidissima has not been adequately developed. Radio telemetry would be an excellent tool to monitor the passage of young shad, however, the current state of the art precludes its use due to the fish's small size and sensitivity to handling. Knight et al. (1977) tagged juvenile American shad with external miniature transmitters and found tag retention in aquaria ranged from a few hours to 5 days. Since the transmitter might detach easily, this tagging method may be unsuitable for passage studies. Ideally, shad should be tagged internally to prevent transmitter loss and eliminate transmitter drag. The objective of this paper is to report on a reliable monitoring technique suitable for turbine passage studies of juvenile American shad. The suitability of this technique was tested in the laboratory and at an operating hydroelectric station on the lower Susquehanna River using both live and dead shad.

METHODS

Laboratory Studies

Shad were collected in an 8 ft square lift net from the inner forebay of a hydroelectric station. The net was equipped with a removable 4 gal stainless steel bucket in its center. When the net was raised and most of the shad were concentrated in the bucket, it was retrieved with an attached rope which ran through a pully on the end of a lift net beam. Specimens were carefully poured into a 12 gal cooler and transferred to a transport tank.

Two methods of radio tagging young American shad were investigated in the laboratory. One was stomach insertion of simulated transmitters (dummy tags) into young shad; the other was attachment of external tags. Simulated transmitters were constructed by potting scotchcast in #1 and #0 gelatin capsules; No. 0 capsules are similar in size to actual transmitters. Dimensions of dummy tags are presented in Table 1.

Shad to be internally tagged were individually water brailed to a 50 mg/l quinate anesthesia bath for 1.3 min. Time for loss of equilibrium was recorded. They were then placed in a tank of fresh flowing water, force fed a dummy transmitter, and held into the current until they swam away. Individuals were observed until equilibrium was regained and times noted. Normally, those not regaining equilibrium after three minutes were sacrificed. The only exceptions were during tests at low water temperatures (5.0 C). Control fish were handled in the same manner as test fish except for transmitter insertion. Data taken for control fish included time in anesthesia (same as test fish) and time to regain equilibrium. Control fish were frequently marked by clipping the upper or lower caudal fin. Mortalities were enumerated and processed after 24, 48, and 72 h. Dead test fish were measured and dissected to determine tag placement and internal damage. Dead control fish were measured only. All live test fish at the end of each experiment were sacrificed, measured (FL), and dissected.

Dummy transmitters used for external attachment were constructed to be positively, neutrally, and negatively buoyant. All were made with Scotchcast potted in #00 and #0 gelatin capsules with small glass beads added for buoyancy. Approximately 2.5 to 5 in. of thin stranded stainless steel wire was potted into one end of each tag to provide a means of attachment. The wire was secured onto a #6 fish hook.

Test specimens were individually water brailed to a tank containing fresh flowing water. They were hand-held into the current and tagged by inserting the hook laterally through the dorsal-most musculature, just posterior to the dorsal fin. Control specimens were handled the same as test specimens except for transmitter attachment. Most fish were held up to 120 h. Dead test fish were measured and tag type and number were recorded. Dead control fish were measured only. All tagged survivors and controls at the end of each test were sacrificed and measured. Tag type and number were recorded.

Field Studies

Radio transmitters for field studies were supplied by H-Cubed Corporation, Columbia, Maryland. They transmitted in the 48-50 MHz band and had a life expectancy of at least 3 days. Each cylindrical tag was approximately 7 x 22 mm, weighed 1.9 g and had a 200 mm whip antenna. Shad were sacrificed and tags inserted into their stomachs. Tags (same type) used for external attachment were placed in #00 or #000 gelatin capsules and coated with liquid plastic tool handle compound. Air was trapped inside the capsules making them slightly buoyant. After modification, tags were 9 x 32 mm and weighed 3.4 g in air. A #6 fish hook and monofilament line were attached to each transmitter. Shad were tagged just posterior to the dorsal fin.

Shad were introduced into the penstock of an operating unit of a hydroelectric station with a specially constructed apparatus. Two tanks of water were coupled to a 40 ft x 8 in. diameter PVC pipe by an 8 in. diameter flexible hose (Figure 1). A butterfly valve was opened causing both tanks to drain directly into the penstock. Shad were placed into the smaller tank before it drained completely. Signals were detected using Advanced Telemetry Systems (Isanti, MN) programmable scanning receivers with boat mounted five element Yagi antennas.

RESULTS

Laboratory Studies

A total of 286 young shad (range 120-194 mm x = 151.6 mm) was tagged with simulated transmitters. An additional 294 shad (100-173 mm, x = 135.9 mm) acted as controls (Table 2).

Overall, 92 shad were internally tagged with #1 Scotchcast dummy transmitters. Cumulative mortality was 28.3, 41.3, and 48.9% over 24, 48, and 72 h, respectively. There were 111 shad tagged with #0 Scotchcast tags and 116 controls. Mortality was 33.3, 67.6, and 77.5% over 24, 48, and 72 h. No. 0 tagged shad 160-169 mm (n=30) had 76.7% survival over 24 h. Although specific data were not taken, observations indicated most mortality occurred after 8 h. Mortality for both #0 and #1 was slightly lower for full tags than for concave tags. Mortality for all internally tagged shad generally decreased with increased size (Table 3). Observations indicated most mortality occurred at least 8 h after tagging.

Approximately one-third of all shad tagged with #1 Scotchcast dummy transmitters had ruptured stomachs (Table 4). Stomachs were ruptured in just over half of the shad tagged with #0 Scotchcast tags.

The dimensions of dummy tags used for stomach insertion are presented in Table 1. The most important dimension was the maximum circumference. Volume and weight were considered less important. Length of the tag was least important since there was less mortality associated with the full dummy transmitter.

External dummy transmitters were attached to 83 shad. Mortality was monitored for 72 h in one test; the remaining were terminated after 120 h. Cumulative mortality during the 72 h test was 25.0, 41.7, and 54.7% over 24, 48, and 72h, respectively for tagged shad. Cumulative control mortality was 8.3, 8.3, and 29.2% (Table 5). Mortality over time was generally uniform with little difference between size groups.

Cumulative mortality of shad held for 120 h was 5.1, 20.3, 28.8, 59.3, and 72.9% over 24, 48, 72, 96, and 120 h, respectively (Table 5). Overall, mortality of tagged shad increased slightly after 24 h but increased markedly after 72 h. Differences in mortality between size groups was slight. Control mortality increased over time, similar to that of tagged shad. However, mortality for controls generally decreased with increased size.

Field Studies

Nineteen dead shad were passed through a generating unit of a hydroelectric station. Eleven were tagged internally and eight were tagged externally. Signals were received from several specimens while they were passing through the station. All signals were located in the tailrace within minutes after induction.

All internally tagged specimens settled on the river bottom within 500 ft of the operating unit in less than 10 min after passage (Figure 2). Eight settled in water depths of 5 to 32 ft. Three settled in turbulent areas where depths could not safely be determined.

Four externally tagged specimens settled in the same area as those tagged internally. The remaining four drifted beyond this area (Figure 2). Two were recovered with the tags still attached. Only the detached tags were recovered from the other two shad. However, one of these was initially observed floating with the tag intact.

DISCUSSION

Laboratory Studies

Mortality generally decreased as fish size increased for each tag size in laboratory tests. Thus, the probability for survival of internally tagged shad should increase with fish size and decrease with transmitter size. For each tag size, mortality generally decreased as fish size increased. The larger #0 tag was responsible for greater mortality than the #1 tag in shad of similar size. Since mortality was generally low within 8 h after tagging, this method is feasible for an acute turbine passage study.

Tag circumference was the most important dimension because of it's role in the stomach insertion procedure. Typically, a tag met resistance when pushed through the esophagus of a shad. The degree of resistance and subsequent trauma to the shad depended on the size of the fish and the circumference of the tag. Once through the esophagus and in the stomach, tag volume was a consideration. Indications were, however, that the volume of tags was not excessive despite the number of ruptured stomachs observed during necropsy. In most specimens with ruptured stomachs, the rupture occurred along the dorsal, anterior portion of the fore gut in the area where the esophagus met the stomach. Presumably, as a tag entered the stomach, the more delicate stomach tissue expanded and either tore or was severely weakened. Although the ruptures may have occurred immediately after tagging, behavior and swimming ability was not noticeably influenced.

Tag weight is a consideration but its importance was not readily discernible. Specimens tagged with #1 concave tags (lightest) did not exhibit behavior different than those tagged with #0 full dummy tags (heaviest).

Another tagging method investigated was the external attachment of transmitters to shad. Although mortality during this study was excessive, investigations were preliminary and depletion of the shad stock precluded further research in the laboratory. Nevertheless, investigations provided valuable insight into methodology. Application of external tags to shad may be size independent since there was little difference in mortality between size groups.

An important variable affecting shad behavior and mortality was the type of external transmitter. Five basic types were tested (Table 1). All but the #0 white tag, approximated the dimensions of transmitters used in the field studies. The major differences between dummy tags were buoyancies and in some, the incorporation of swivels. Only 22.2% of the shad tagged with #00 chrome swivel tags died before test termination. This was substantially lower than the other external tags. This tag was differentiated from the others by it's slightly positive buoyancy and swivel. Other tag types were either buoyant or negatively buoyant. The effect of the swivel on the increased survival of shad is unknown. Presumably, it decreased torque on the attachment hook and lessened irritation in that area. Further investigations of external tags will attempt to isolate factors which will increase survivability.

Field Studies

Both internal and external transmitters tested were satisfactory for this study. Signals were strong enough to locate all fish which were passed through the station. This transmitter type should be applicable at other hydro sites. Factors which may limit their use are deep tailwaters, extreme noise levels and site accessibility. Previous performance tests of similar tags resulted in signal loss at water depths of 35-40 ft. Background noise, which is prominent at power stations, may be intense enough to mask radio signals. Since the range of this tag is more limited than conventional transmitters, closer proximity to tagged specimens is necessary.

Half of the external transmitters sank after passage through the station. This was probably due to transmitter capsule damage (mechanical or differential pressure) which caused the tags to sink. Transmitter encapsulation improvement is warranted to delineate specimen mortality from transmitter failure.

ACKNOWLEDGMENTS

We thank Mr. William F. McElroy and Mr. Howard F. Hansell (Philadelphia Electric Company), Mr. Donald B. Chubb (Safe Harbor Water Power Corporation), and Dr. Elizabeth I. Bauereis (Baltimore Gas and Electric Company) for their review and comments. Philadelphia Electric Company and Safe Harbor Water Power Corporation provided support for this study.

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TABLE 1

Characteristics of dummy tags and transmitters.

Internal	Average Length (mm)	Average Diameter (mm)	Maximum Circum. (mm)	Average Volume (cc)	Average Weight (g)
#1 Concave	16.7	6.0	18.9	0.44	0.55
#1 Full	19.5	6.0	18.9	0.50	0.65
#0 Concave	18.3	7.0	22.0	0.66	0.74
#0 Full	21.5	7.0	22.0	0.74	0.83

External	Average Length (mm)	Average Diameter (mm)	Average Weight* (g)	Bouyancy
#00 bl. swivel	25.0	8.8	1.89	Negative
#00 ch. swivel	27.3	9.2	1.59	Slightly positive
#00 white	26.8	8.5	1.30	Positive
#00 creme	24.0	9.0	1.49	Variable
#0 white	22.3	6.5	0.99	Variable

*Includes hook, swivel (if any), wire and tag

TABLE 2

Summary of young American shad and dummy tag types used in experiments at the Muddy Run Ecological Laboratory.

	#1 Internal	#0 Internal	External	Total
No. Test Fish	92	111	83	286
Size Range (mm)	126-177	137-194	120-175	120-194
X Size (mm)	152.9	157.6	142.3	151.6
No. Control Fish	95	116	83	294
Size Range (mm)	100-171	107-168	105-173	100-173
X Size (mm)	137.8	135.9	133.9	135.9

TABLE 3

Cumulative mortality of young American shad tagged internally with scotchcast dummy tags.

Fork Length (mm)	#1 Full Cumulative Mortality (%)				#0 Full Cumulative Mortality (%)			
	n	24h	48h	72h	n	24h	48h	72h
130-139	5	60.0	80.0	80.0	0	--	--	--
140-149	8	50.0	62.5	62.5	5	60.0	100.0	100.0
150-159	10	10.0	10.0	40.0	19	47.4	84.2	89.5
160-169	9	11.1	22.2	22.2	17	17.6	41.2	58.8
170-179	3	0.0	0.0	0.0	10	20.0	60.0	60.0
180-189	0	--	--	--	1	0.0	0.0	0.0
190-199	0	--	--	--	1	0.0	0.0	0.0
Totals	35	25.7	34.3	42.9	53	32.1	64.2	71.7

Fork Length (mm)	#1 Concave Cumulative Mortality (%)				#0 Concave Cumulative Mortality (%)			
	n	24h	48h	72h	n	24h	48h	72h
<130	1	100.0	100.0	100.0	0	--	--	--
130-139	8	37.5	50.0	62.5	4	25.0	75.0	75.0
140-149	13	30.8	61.5	69.2	13	61.5	84.6	84.6
150-159	16	18.8	43.8	50.0	26	26.9	65.4	88.5
160-169	12	25.0	25.0	33.3	13	30.8	76.9	84.6
170-179	7	42.9	42.9	42.9	2	0.0	0.0	0.0
Totals	57	29.8	45.6	52.6	58	34.5	70.7	82.8

Fork Length (mm)	#1 Combined Cumulative Mortality (%)				#0 Combined Cumulative Mortality (%)			
	n	24h	48h	72h	n	24h	48h	72h
<130	1	100.0	100.0	100.0	0	--	--	--
130-139	13	46.2	61.5	69.2	4	25.0	75.0	75.0
140-149	21	38.1	61.9	66.7	18	61.1	88.9	88.9
150-159	26	15.4	30.8	46.2	45	35.6	73.3	88.9
160-169	21	19.0	23.8	28.6	30	23.3	56.7	70.0
170-179	10	30.0	30.0	30.0	12	16.7	50.0	50.0
180-189	0	--	--	--	1	0.0	0.0	0.0
190-199	0	--	--	--	1	0.0	0.0	0.0
Totals	92	28.3	41.3	48.9	111	33.3	67.6	77.5

Fork Length (mm)	#1 Controls Combined Cumulative Mortality (%)				#0 Controls Combined Cumulative Mortality (%)			
	n	24h	48h	72h	n	24h	48h	72h
<130	31	6.5	12.9	25.8	32	9.4	25.0	43.8
130-139	21	23.8	28.6	33.3	30	3.3	16.7	23.3
140-149	9	11.1	11.1	11.1	30	3.3	6.7	16.7
150-159	22	4.5	9.1	9.1	19	0.0	0.0	5.3
160-169	11	0.0	0.0	0.0	5	0.0	0.0	0.0
170-179	1	0.0	0.0	0.0	0	--	--	--
Totals	95	9.5	13.7	18.9	116	4.3	12.9	23.3

TABLE 4

Percentage of young American shad with ruptured stomachs by size and tag type.

Fork Length (mm)	#1 Concave	#1 Full	#0 Concave	#0 Full	Total
< 140	60.0	40.0	75.0	--	57.9
140-149	16.7	50.0	57.1	80.0	46.2
150-159	43.8	50.0	62.1	63.2	56.8
160-169	16.7	11.1	53.8	47.1	35.3
170-179	0.0	33.3	50.0	60.0	36.4
180-189	--	--	--	0.0	0.0
190-199	--	--	--	0.0	0.0
Average	29.8	37.1	59.7	56.7	46.9

TABLE 5

Cumulative mortality of young American shad tagged externally with dummy transmitters during 3 and 5 day tests.

Three Day Test		Mortality (%)		
Size (mm)	n	24h	48h	72h
<130	7	0.0	42.9	57.1
130-139	13	46.2	46.2	53.8
140-149	2	0.0	50.0	50.0
150-159	2	0.0	0.0	50.0
Total	24	25.0	41.7	54.2

Control Mortality (%)

Size (mm)	n	24h	48h	72h
<130	11	0.0	0.0	9.1
130-139	7	14.3	14.3	57.1
140-149	3	0.0	0.0	0.0
150-159	3	33.3	33.3	66.6
Total	24	8.3	8.3	29.2

Five Day Test		Mortality (%)				
Size (mm)	n	24h	48h	72h	96h	120h
<130	5	0.0	0.0	20.0	60.0	80.0
130-139	15	0.0	20.0	40.0	73.3	80.0
140-149	11	0.0	27.3	36.4	54.5	72.7
150-159	19	10.5	26.3	26.3	57.9	73.7
160-169	8	12.5	12.5	12.5	37.5	50.0
170-179	1	0.0	0.0	0.0	100.0	100.0
Total	59	5.1	20.3	28.8	59.3	72.9

Control Mortality (%)

Size (mm)	n	24h	48h	72h	96h	120h
<130	24	4.2	16.7	25.0	37.5	54.2
130-139	16	0.0	18.8	18.8	25.0	37.5
140-149	8	0.0	0.0	0.0	12.5	50.0
150-159	6	0.0	0.0	0.0	0.0	16.7
160-169	4	0.0	0.0	0.0	0.0	0.0
170-179	1	0.0	0.0	0.0	0.0	0.0
Total	59	1.7	11.9	15.3	23.7	40.7

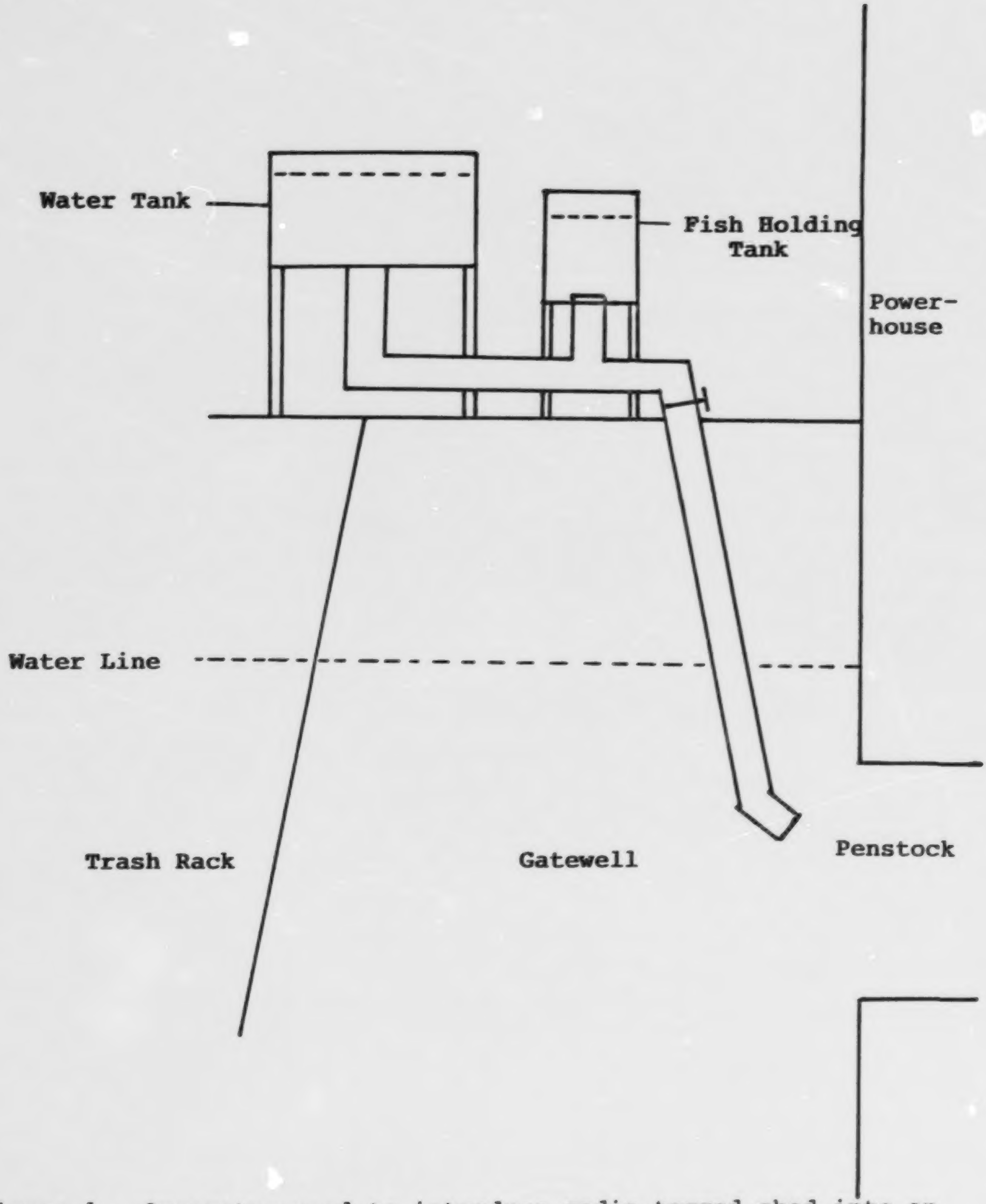
Water Tank
Fish Holding Tank
Power-house
Water Line
Trash Rack
Gatewell
Penstock

Figure 1. Apparatus used to introduce radio tagged shad into an operating unit.

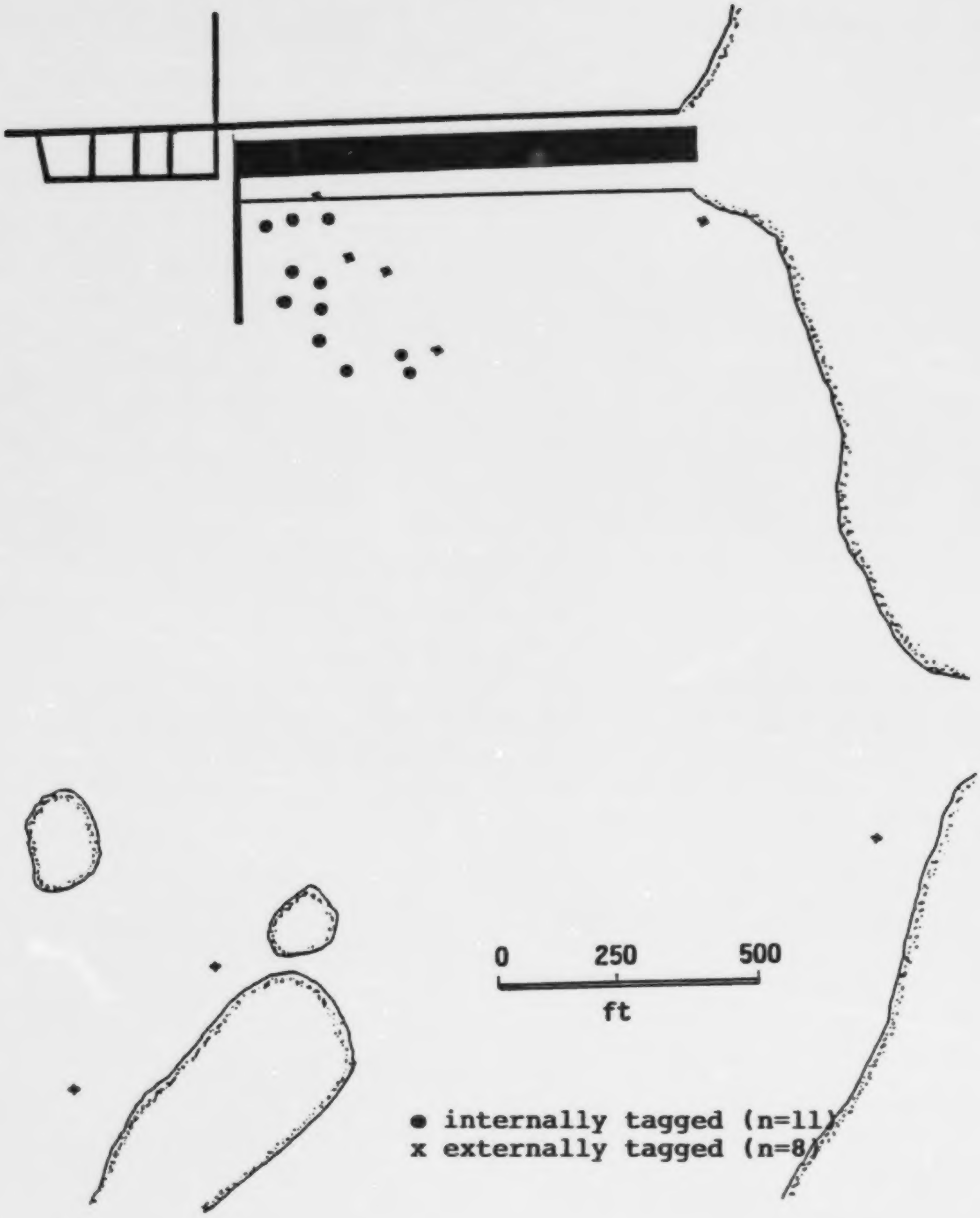
0
250
500
ft
● internally tagged (n=11)
x externally tagged (n=8)

Figure 2. Locations of 19 sacrificed radio tagged American shad passed through a single operating unit.

SESSION 13:

SMALL HYDRO PLANNING ' A'

Chairperson: A. McKechnie
Acres International Limited

The Pros and Cons of Streamlining the Small Hydro Engineering Process

By
K.J. Bennett

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THE PROS AND CONS OF STREAMLINING THE SMALL HYDRO ENGINEERING PROCESS

Kearon J. Bennett, P. Eng.
President, Ottawa Engineering Limited

ABSTRACT

The success of small hydro depends to a large extent on the engineering industry's ability to provide cost-effective services. Small hydro cannot, generally, support the conventional multi-tiered approach to the development of large projects. However, as the scope of engineering is reduced, the risk that must be assumed by the developer increases.

The intent of this paper is to provide prospective, inexperienced developers (Canadian and international) with some guidelines for determining the engineering services required for individual small hydro projects.

By starting with a detailed list of the engineering tasks that can be involved in a large hydro project from conception through studies, design and construction, a short-list of the essential items is developed and the risk involved with streamlining the approach is discussed.

INTRODUCTION

Every hydro site, small or large, is unique. While this is a very "broad-brush" statement, it is nevertheless true almost without exception.

The assessment, design and implementation of a small hydro project involves a large number of engineering disciplines: hydrologic; hydraulic; structural; geotechnical; mechanical; and electrical. The problems to be solved by each discipline can range from elementary to extremely complex.

While it is true that the detail involved in the engineering process can be the same for either large or small hydro projects, it is clear that small hydro cannot economically support the cost of the large hydro engineering approach.

THE CONVENTIONAL APPROACH

The conventional approach to the development of a typical large hydro project follows a time-tested, multi-tiered engineering process which is usually made up of the following key elements carried out in succession:

RECONNAISSANCE STUDY

PRE-FEASIBILITY STUDY

FEASIBILITY STUDY

FINAL DESIGN

TENDER DOCUMENTS

BID EVALUATION

AWARDING OF CONTRACTS

PROJECT MANAGEMENT AND CONSTRUCTION SUPERVISION

COMMISSIONING

Each item listed above is a heading for a number of sub-tasks. The level of detail increases as the project progresses through the various study and design phases.

Studies involve hydrologic, hydraulic, geotechnical and economic evaluations, the detail of each depending on the availability of data and complexity of the project. Final selection of the installed capacity will be the result of a detailed optimization process.

As one can appreciate, the process is expensive; and for a large project justifiably so. Little can be left to chance when the final project cost will be many millions (or billions) of dollars.

SMALL HYDRO - THE ESSENTIAL ITEMS

Of the many studies and investigations that can be included in the implementation process of a small hydro project, it is clear that there are a number of essential items that must be addressed:

Potential Barriers to Development: The potential barriers to development must be assessed early in the study phase. For example, there is little point pursuing the development of a project that is doomed from the start due to severe environmental restrictions. There are very few, if any, small hydro projects that can support the cost of lengthy public hearings.

Hydrology: The flow at a site is usually, by far, the biggest unknown factor. Head and efficiencies, the other components of the power equation, can easily be measured and estimated.

The level of effort that is required to estimate the flow at a site may be significant if there are no established streamflow gauges nearby. Many hydrological procedures exist for estimating the flows at ungauged sites, but often the best approach is to verify by measurement.

The key word here is "estimate". Even the time consuming measurement of streamflow using current meters at a cross-section in a river is not exact, no matter how ideal the situation may be.

An assessment of the level of accuracy of the measured or synthesized streamflow data that will be used to size the installation and arrive at the projected revenue must be made. The effects on the economics of the project due to negative changes in the hydrologic patterns at the site must be checked, especially the effects of low-flow years.

Another aspect of the hydrologic analysis is the estimation of the appropriate flood flow to be used for design. Flood flow estimates are, at best, inexact. The developer should be made aware of the potential risk involved due to flooding at a site and be advised as to the extent protection should be provided. In some cases, designing for the maximum probable flood could render the project uneconomical.

Geology: Unanticipated geological problems are often encountered during the construction of hydro projects. The associated delays and extra costs can easily render an initially attractive project uneconomical.

As a minimum, qualified geotechnical advice should be sought to identify any potential problems and the probability of these occuring. Associated potential additional costs should also be assessed.

Demand/Supply: For small hydro plants that are to be interconnected to a large grid system, the study of demand and supply becomes relatively straightforward. Since demand can be considered infinite the problem reduces to selecting the most economic size of the installation based on capacity and energy output.

When a small hydro plant is to supply a remote load centre the problem becomes one of selecting the appropriate capacity based on an assessment of the resource potential and the projected load growth. Estimated and worst case scenarios should be considered and provisions for future expansion (if the resource allows) should be incorporated into the design.

Cost and Economics: Estimating the cost and assessing the economic viability of a small hydro project deserves special attention.

The task of costing can be simplified by using historic information and soliciting estimates from equipment and construction contractors.

Assessing the economic viability of the project is a straight forward process but requires careful thought. The sensitivity of the project feasibility to reasonable changes in the costs and benefits should be checked.

Contracting: Once a decision is made to proceed with construction, the most important item becomes contracting. Legal advice should be sought and some form of competitive process should be employed to ensure that the contractors are qualified to do the work.

Price, although important, should not automatically be placed ahead of qualifications when selecting contractors. A low price from an inexperienced contractor may well be unrealistic.

Quality construction will pay dividends over the life of the project and is therefore worth some additional initial expense.

Advice During Construction: The developer is wise to have unbiased, professional advice during construction. While the overall management of the project can often be undertaken by the developer, construction will frequently require design modifications and special solutions for which a second opinion is recommended.

Even if the project is being done on a turnkey basis with the contractor being responsible for the design and construction, a second opinion is advisable.

Judgement is required to determine the level of effort required in each of the tasks listed above. As with a large project, some tiering of the process is recommended to avoid unnecessary expense. Good advice based on relevant experience is probably the most essential part of the development process.

SUGGESTED APPROACH TO SMALL HYDRO DEVELOPMENT

In order to reduce the effort, and hence the cost, of the small hydro engineering process, the work can be simplified into the following phases of work:

1) Initial Assessment
2) Feasibility Study
3) Final Design or Specifications for Turnkey Contract
4) Contracting
5) Advice During Construction and Start-up

The following is a brief description of the work involved in each of these phases.

1) Initial Assessment

The Initial Assessment phase should involve the following tasks:

- Identification of the potential barriers to development
- Preliminary hydrologic analysis
- Preliminary estimate of the potential revenue, costs (using documented costing information) and economics of several development alternatives
- Sensitivity analysis incorporating reasonable changes to the assumptions used

2) Feasibility Study

If the results of the first phase warrant further work, the next phase would be a feasibility study of sufficient detail to allow the developer and a lending institution to make a decision regarding funding for the implementation of the project.

The feasibility study should elaborate on the results of the preliminary assessment. The tasks would be basically the same except more effort would be required. For example, additional hydrologic studies would be carried out if required and costs would be based on quotes from suppliers and contractors. Geological advice would be solicited at this stage. The economic analysis would be expanded into a financial analysis evaluating anticipated cash-flows based on the projected revenues and current interest rates. Two or preferably three alternatives should be compared to arrive at the selected scheme. Preliminary design drawings should be prepared.

3) Final Design or Specifications for Turnkey Contract

Both turnkey development, where the design and construction of the project is carried out by the same group, and the conventional approach, which involves independent design and construction teams, should be investigated. Each has its merits. The turnkey approach limits developer responsibility and liability for delays and cost overruns while the conventional approach provides more flexibility and allows maximum involvement of the developer.

If turnkey development is selected, a set of specifications should be established which clearly identifies the objectives and limitations of the project.

Otherwise, the design phase should involve the preparation of basic working drawings with only the information required by a qualified contractor to construct the project. Standard designs should be used where possible. Specifications should be brief, concise and allow the contractor a certain amount of flexiblility.

4) Contracting

The selection of contractors should involve a competitive process as described in the previous section. The emphasis should be placed more on quality than price.

This phase should involve the help of a lawyer for the preparation of clear and workable contracts.

5) Advice During Construction

This task should involve periodic inspection of the construction site and the preparation of inspection reports by a qualified engineer. Because of the relatively superficial nature of the initial field investigation it must be accepted that revisions to the design may be necessary if the original assumptions prove to be inaccurate. The engineer should have the authority to direct the contractor on the developer's behalf if required but would not be required to take responsibility for the work. Responsibility for the quality and integrity of the work would remain with the contractor.

The following are some guidelines to keep in mind when carrying out the procedure described above.

- When making an assessment of the potential revenue at a site, use realistic values for the operating range, efficiencies and down-time for small hydro equipment.
- Attempt, at a very early stage, to get an appreciation of the work involved including the potential problems.
- Employ unbiased advice for the evaluation of proposals and bids from contractors, manufacturers and/or turnkey organizations.
- Use qualified, experienced individuals and companies with proven track records which are easily verified. This is particularilly important when it comes to the equipment manufacturer.
- Avoid excessive sub-contracting which can lead to management nightmares and unnecessary delays.

- Request maximum input from the equipment manufacturer during the design phase to avoid both "re-inventing the wheel" and future operation and maintenance problems.
- Seek second opinions for the solutions to difficult engineering problems.
- Use designs and specifications that are simple and which allow the contractor flexibility during construction to select a preferable solution if one arises.
- Budget comfortable contingency amounts, based on conservative estimates, to cover unexpected expenses.
- Liase closely with the engineer throughout the entire process.

THE RISKS

What are the chances of cost overruns and how much might they be? What chance is there for lower than anticipated revenues? Will the project be safe from potential natural disasters?

"You get what you pay for." Reducing the level of engineering involved in the implementation of a hydro project increases the chances of poor project performance both due to potential cost overruns and potentially lower revenues. The risk of damage due to natural disasters is also increased.

Nevertheless, small hydro projects cannot support detailed engineering studies and design that are common to large hydro development. It is clear, therefore, that the small hydro developer must be prepared to accept a greater risk than the large hydro developer.

The small hydro developer should be made aware in writing of the anticipated risks involved at the outset of a project. In this way appropriate contingencies can be incorporated into the assessment of the economic viability of the project.

CONCLUSIONS

The small hydro engineering process can be streamlined but not without increased risk.

The suggested simplified approach involves a five stage as opposed to the conventional nine stage development process employed for large hydro projects. The five major tasks combine to cover all the tasks involved in the large hydro process but in much less detail as follows:

LARGE HYDRO	SMALL HYDRO
Reconnaissance Study Pre-feasibility Study	Initial Assessment
Feasibility Study	Feasibility Study
Final Design Tender Documents	Final Design or Specifications for Turnkey Contract
Bid Evaluation Awarding of Contracts	Contracting
Project Management and Construction Supervision Commissioning	Advice During Construction and Start-up

Simplified designs and specifications should be used.

An assessment of the risk involved must be made based on sound judgement and be clearly documented to allow the developer to make a decision as to whether or not to proceed.

Contingencies, based on conservative estimates, should be included in the project budget.

A developer should not proceed with the development of a marginal project that has not been studied sufficiently to reduce the level of risk.

In summary, small hydro cannot bear the full cost of the conventional large hydro engineering process. As engineering efforts decrease, risk increases. The risk must be understood and accepted by the small hydro developer.

Small Hydro:
The Canadian Federal Experience and Outlook

By
D. Strange

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SMALL HYDRO: THE CANADIAN FEDERAL EXPERIENCE AND OUTLOOK

Dr. D.L.P. Strange

Director General
Renewable Energy Branch
Energy, Mines and Resources Canada

June, 1988

Presented at Small Hydro '88
July 4-9, 1988
Toronto, Ontario

SMALL HYDRO: THE CANADIAN FEDERAL EXPERIENCE AND OUTLOOK

1. INTRODUCTION

I'm pleased to be here this afternoon to speak to you on behalf of the Renewable Energy Branch of the Department of Energy Mines and Resources.

I would first like to thank the conference organizers for the opportunity to address the delegates, and I would also like to pass my personal compliments to the various officials from the Ministry of Energy for organizing such an impressive and well run event. Ontario is perhaps Canada's most active province in the field of small hydro development and indeed many of the recent advances in this field have taken place in Ontario.

In the next ten to fifteen minutes I will give you a brief outline of the federal program supporting of Small Hydro development in Canada. I will try to identify the barriers that stand in the way of developing small hydro energy and outline what we are doing through the Department of Energy, Mines and Resources to overcome the barriers and accelerate the implementation of worthwhile small hydro energy projects.

2. EVOLUTION OF SMALL HYDRO IN CANADA

Hydro-electricity has a long history as an energy source for Canadians. Since the completion in 1882 of one of North America's first hydroelectric generating facilities at Chaudiere Falls in Ottawa to provide electric lighting for a local sawmill, hydropower has played an important role in Canada's economic development.

Hydro-electric power is also a very big business in Canada. Today, Canada has about 60,000 MW of installed hydroelectric capacity. This represents 2/3 of total electricity generation in the country. The provinces of Québec, British Columbia and Manitoba produce most of their electric power from large hydroelectric stations. There are more than four hundred hydro stations in Canada now, which are owned by utilities and companies. One fifth of all those stations account for 90% of the total hydro capacity. They are the ones that have a capacity of 100 MW or larger. About half the total number of hydro stations in the country have a capacity of less than 15 MW and they could easily be labelled small hydro stations. They account for about 2% of the total hydro capacity in Canada.

When hydro-electricity was started in this country in the past century it was the dream of every community and every company to become energy independent. During the early part of this century it became evident, however, that small hydroelectric developments could not, in the long term, supply the rapidly increasing power needs of the many Canadian towns and villages growing up within the 150-mile band along Canada's southern frontier. During the same period, the development of efficient transformers opened the option of the long distance transmission of electricity in the country.

It was also recognized that the economies of scale dictated the establishment of much larger hydroelectric stations where there was ample water supply and then transport electricity where it was needed. In other words, it became clear that the manufacturing plants did not have to be located exactly where the energy supply was and that the energy could be transported where it was needed.

The establishment and continuous expansion of grid electricity essentially spelled the beginning of the end of small hydro stations. The financial viability of small scale hydro power in grid-serviced areas was severely affected and in most situations they were eliminated. A great many small hydro plants which had been incorporated into the public utility systems were decommissioned following the Second World War.

The energy crises of the 1970's essentially re-established the small hydro energy option as a cost-effective and clean source of renewable energy. It has been well recognized in the last few years that small hydro is an excellent alternative to diesel generators in off-grid locations. Site inventory studies carried out during the past five years indicate that the total undeveloped potential of small hydro stations is at least 2,000 MW at about 1,200 sites in the provinces and Territories (Figure 1). This large potential is located first in Québec with 600 MW, second in Ontario with 500 MW, thirdly in B.C. with 300 MW. The Atlantic provinces of New Brunswick, Nova Scotia and Newfoundland also account for another 500 MW of potential small hydro capacity.

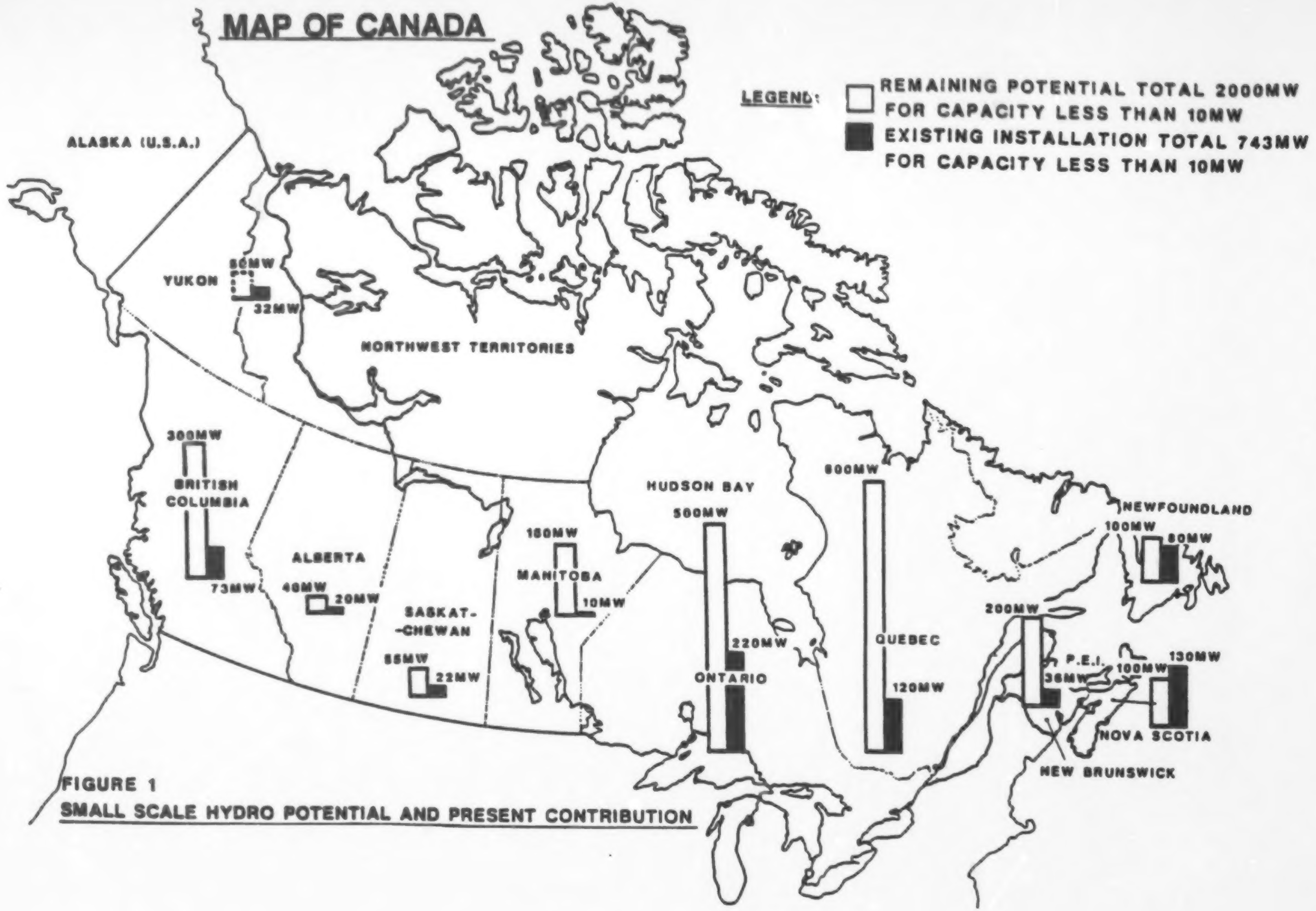
MAP OF CANADA
LEGEND:
REMAINING POTENTIAL TOTAL 2000MW FOR CAPACITY LESS THAN 10MW
EXISTING INSTALLATION TOTAL 743MW FOR CAPACITY LESS THAN 10MW
ALASKA (U.S.A.)
YUKON
50MW
32MW
NORTHWEST TERRITORIES
BRITISH COLUMBIA
300MW
73MW
ALBERTA
40MW
20MW
SASKAT-CHEWAN
55MW
22MW
MANITOBA
150MW
10MW
HUDSON BAY
ONTARIO
500MW
220MW
QUEBEC
800MW
120MW
NEWFOUNDLAND
100MW
80MW
P.E.I.
200MW
36MW
100MW
130MW
NOVA SCOTIA
NEW BRUNSWICK

FIGURE 1

SMALL SCALE HYDRO POTENTIAL AND PRESENT CONTRIBUTION

3. CONSTRAINTS TO SMALL HYDRO DEVELOPMENT

Notwithstanding the large small hydro potential awaiting exploitation, activity in this field in Canada has been modest when compared with the strong resurgence of small hydro development in other industrialized countries. There are undoubtedly a number of factors at work to constrain such activity in Canada. They include economic, institutional, technological and lack of information constraints.

3.1 ECONOMIC CONSTRAINTS:

Among the economic barriers, the two most important ones are the initial capital costs with the associated financing difficulties, and the buy-back rates and policies of utilities for generated power by independent producers.

. HIGH CAPITAL COSTS

In off-grid locations, the initial costs for small diesel plants are relatively low, typically $800 to $1,500 per kilowatt, whereas small hydro costs are usually several times higher, depending on the specific project. Even when the installation of a hydro project can be demonstrated to reduce future diesel fuel purchases sufficiently to produce net benefits over the life of the project, most owners are reluctant or unable to proceed with the hydro project because of high capital costs. A hydro plant with 25 kW capacity, capable of serving only a few families, could involve an initial outlay of $100,000 ($4,000 per kW) and possibly more.

Private individuals or small firms and remote communities often cannot afford the initial costs of installing small hydro. They have little capital and very limited credit, they are often unable to proceed to implement a small hydro project even if they believed it to be in their long term financial interest in terms of diesel fuel savings.

Industries on the other hand which produce their own power in remote locations usually examine potential investments in generation facilities in the same manner as alternative investment opportunities. Most industries expect relatively short payback periods, typically five years or less, for most of their capital outlays. Hence they are unwilling to invest in hydro projects unless these produce significant cost savings in the early years and result in short payback periods.

. FINANCING DIFFICULTIES

Since capital costs for developing a small hydro site can be substantial, the negotiated terms of a loan to an individual or small company are often difficult and unyielding. That is if the loan is approved at all.

. BUY-BACK RATES

In cases where the small hydro project could be connected to the grid, the buy-back rates for the generated power can be another major barrier for the developer. In fact, if there is no policy for buy-back, the project is usually a no-go situation right away.

Without a guaranteed buy-back rate, the only development that is likely to occur will be at remote sites. Alternatively, the potential developer will design a smaller hydro project to produce only enough electricity to satisfy his/her own demand. Consequently, full development of the potential energy that is available at such a site may not be achieved.

In provinces where reasonable buy-back rates exist, the chances of fully developing potential small hydro are more promising. In these provinces, electricity that cannot be used at the site by the developer, can be sold to the provincial utility. It is only when provincial utilities offer guaranteed buy-back rates for parallel generation that the full potential of small hydroelectric sites will be exploited.

Fortunately, many Canadian utilities have recently established power purchase policies. The offered rates are often based on avoided fuel costs only, without allowances for capital costs. In other provinces, utilities will accept but not repay for surplus power generated, while a few Canadian utilities have established policies of net billing at retail rates.

This price and market access constraint on the marketing of the output from small power projects, coupled with the advantages available to utilities of tax exempt status and access to capital at preferred rates, places small power producers in Canada at a serious competitive disadvantage.

3.2 INSTITUTIONAL CONSTRAINTS:

Proponents serious about developing small hydro sites are faced with several bureaucratic or institutional hurdles in order to obtain approval. These procedural hurdles relate to water rights, electricity distribution, environmental consideration, fisheries and possibly navigation. The increasingly complex and lengthy approval procedures are too demanding for a small hydro development. Even trying to discover the appropriate set of regulations to address, often leaves a proponent frustrated. The existing procedures were established to address large scale projects with major impact. Simplification of these procedures is necessary if the proponent is not to be discouraged in the initial stage.

In addition, design standards and construction procedures applicable to a utility's large projects supplying the grid are often inappropriate to small off-grid projects and cause the latter to be unnecessarily expensive. Reliability criteria, frequency and voltage controls, back-up systems and maintenance requirements for small, remote plants are, in principle, different from larger grid installations.

The current surplus generating capacity faced by most provincial utilities does not auger well for the development of attractive policies and strategies to promote small hydro developments.

3.3 TECHNICAL CONSTRAINTS:

In technical terms, we are essentially addressing the issues of rediscovering small hydro technology.

After more than a half century of "up-sizing" hydro designs, it cannot be assumed that the opposite procedure of "down-sizing" large turbine and accessory designs provides the most cost-effective approach to small development and utilization. Conventional methods of design and engineering result in too high a cost for a small-scale project which should not be regarded simply as a scale model of a large hydroelectric plant.

Thus, it is necessary to re-think the conventional hydro technology and discard many parts and features currently considered necessary on large projects so as to leave only the absolutely essential equipment and facilities required for the production of electricity, with reliability and safety. For example, the site could be designed to match the characteristics of available equipment rather than following the conventional approach for large projects of designing the turbine and generator to match the site characteristics.

Although progress has been made during the past several years by equipment manufacturers in the development of standard or pre-designed components for small hydro stations, there is still much scope for further engineering development. Such development should have particular reference to Canadian requirements and conditions, particularly with regard to the provision of electricity to the remote northern communities where diesel and hydro are the only major viable alternatives for the foreseeable future.

There still remains a wide scope for further simplification and standardization for large scale production, for the application of new materials (plastics, resin, etc.), in the application of computer technology in design, improvement of turbine speed regulation systems and/or operator management techniques such as remote control, micro processors, etc.

4. WHAT'S BEING DONE ABOUT THESE PROBLEMS?

4.1 PROVINCIAL GOVERNMENT AND UTILITIES LEVEL:

The Province of Ontario has undertaken several major activities to promote small hydro development. They include: carrying out an inventory of sites; streamlining regulatory approvals; assistance in carrying out feasibility studies; and demonstration programs. A number of important policy, legal and regulatory precedents have also been established. These include the parallel generation policy at Ontario hydro and policies and rates for "wheeling" of power to different locations.

The provinces of British Columbia, Quebec, Newfoundland, Nova Scotia, and New Brunswick have all encouraged several small hydro demonstration projects during the last five years. Energy, Mines and Resources Canada has contributed financially to these projects through the federal - provincial demonstration agreements.

As mentioned earlier, several other provincial utilities have also established guaranteed buy-back rates for parallel generation. The issue of appropriate power purchase rates has begun to receive increased attention in Canada as more and more small power production opportunities have been identified and as more has been learned about the U.S. experience with its legislation. In fact, EMR contracted to have a study carried out to examine the potential applicability of similar legislation in Canada.

4.2 PRIVATE SECTOR INITIATIVES:

The private sector has taken the bull by the horns in this area and has made excellent progress. Several Canadian companies have shown their ability to service the market with both conventional turbines and support systems as well as with more innovative product designs. These companies, along with other individuals and financial interests, have successfully demonstrated their capability to develop small power production opportunities. The Canadian small hydro turbine industry's annual equipment sales have been between 20 MW to 30 MW in the past few years, representing a $20 to $30 million generating equipment business. Perhaps an equal amount of business has been generated in the engineering and civil construction stages, for an annual total of $40-$60 million.

On the financing issue, the concept of joint ventures, including limited partnerships, and preference share financing has been explored and in many cases these ventures have been successfully managed.

A lease-to-own plan has been devised by Commerce Leasing of the Canadian Imperial Bank of Commerce (CIBC) whereby a developer leases the small hydro facility from the bank and then has the option to purchase the plant when the lease expires. This financial arrangement was developed by the bank for a municipality in Ontario as a result of the municipality's desire to redevelop a small hydro site in the community. Under the terms of this 12-year lease, no lease payments are required during the normally dry months of July and August.

5. FEDERAL ACTIVITIES AND PROGRAMS

5.1 RESEARCH AND DEVELOPMENT

In July 1985 the Canadian Department of Energy, Mines and Resources (EMR) was assigned the responsibility for the federal support program for renewable energy R&D in Canada. Such support is based on established priorities for economic renewal through emphasis on private sector initiatives. The R&D program requires the cost-sharing of projects with industrial performers who seek to develop new or improved products for near-term commercial exploitation. Small hydro development is considered one of the key elements of this program.

R&D PROGRAM GOAL AND STRATEGY

A major requirement with regard to the support of small-scale and low-head hydro developments is the need to reduce the installation cost for existing technology and to demonstrate new techniques and designs that have a reasonable chance for economic application. Specifically, the objective of the Small and Low Head Hydro R&D Program is:

To develop new technologies and improve existing technologies in order to increase the economic viability of selected small-scale and low-head hydro including tidal energy generation options.

In pursuit of this objective, EMR will, to the extent of resources available:

a) Support research directed toward more cost-effective techniques for site selection and analysis, plant design and construction;
b) Support research directed toward more cost-effective prime movers, generators and ancillary equipment;
c) Encourage, in conjunction with other concerned agencies, the growth and development of a competitive and cost-effective Canadian capability for manufacturing hydroelectric machinery;
d) Encourage rationalization and standardization of design, where deemed likely to reduce hydro development costs; and
e) Encourage technical awareness and entrepreneurial interest in small and low-head hydro through the dissemination of technical information.

. R & D PROGRAM PRIORITIES

The R&D priority areas were established as follows:

a) Innovative civil works and components, particularly for remote sites application. These include:
   - modular and dam construction techniques
   - non-dam approach
   - syphon and other cost-effective arrangements
b) Pilot or prototype projects for development of commercial units or systems, including testing and field trial.
c) Development and improvement of cost-effective generating equipment, including:
   - axial flow turbine packages for low-head and medium-head application
   - ultra-low-head turbines
   - submersible packages
   - variable speed or induction generators in off-grid applications
   - automatic controls and standardization of designs
d) Site-assessment methodology and computer models, including CAD/CAE and CAM.

. CANADIAN SMALL HYDRO R & D ACHIEVEMENTS:

a) Resource Assessment Techniques

Studies on hydrologic design methodologies for small scale hydro at ungauged sites have been carried out for the past three years. Application manuals and computer programs have been developed. These provided guidance for determining design flows and flood or current magnitudes at small hydro sites without involving costly studies. In the province of British Columbia, studies have been undertaken using watershed modelling techniques.

A user friendly micro computer program for costing small hydro has been prepared by consultants for EMR. The computer program

"SHYDRO" is available to the public and can be integrated with hydrology programs already developed to estimate the cost of components of potential hydro development.

b) Technology Development

The National Research Council has developed a turbine test facility to assist Canadian turbine maufacturers and inventors to develop new, novel and more competitive machines.

A unique turbine arrangement has been tested for an Ontario small hydro turbine manufacturer. This low-cost, but very efficient, turbine has now been installed commercially at more than fifteen sites with power outputs ranging from 30 to 500 kW.

A low-head axial flow turbine with electronic governor has been developed by University of Laval, Quebec. The prototype (20 kW) has been installed at a remote community site and has been in service for four years. Various field test techniques and instrumentation have been developed and this turbine should be commercialized within the next year or so.

. PRESENT R & D ACTIVITIES AND PROJECT HIGHLIGHTS:

The Hydraulic Energy R&D Program, with a $500,000/year budget, awarded fourteen contracts through a Request for Proposal (RFP) process in 1986. Another fifteen projects were awarded in 1987. During the formative stages of the program, EMR decided it should work in partnership with the private and institutional sectors to ensure the maximum level of cooperation. A Technical Advisory Committee (TAC) was established with members from public and private industry to provide expert technical advice, assist in planning the program priorities, evaluate proposals and direct program activities.

R&D projects were briefly described in the Project Summary report prepared by EMR and are available at this Conference. Several interesting projects are described in the following sections:

a) New Turbine and Product Improvement

i) Development of a High-Head Axial-Flow Off-Grid Mini-Hydro System:

Mechanical and electrical engineering staff from Laval University, Quebec, have designed, carried out model tests on, and constructed a prototype of an axial-flow tubular turbine package for a remote vacation camp site. The turbine is rated at 20 kW for a nominal head of 6 m. It could produce up to 80 kW under an appropriate head. Extensive field testing and monitoring have been carried out and the plant has been operating successfully for the past five years [Netsch, 1985]. Work is currently underway to design, fabricate and field test a 120 kW system for a head of 30 m and with an optional variable speed generator coupled directly to the turbine.

The turbine has a 0.5 m diameter runner with fixed blades and guide vanes. Since the design head is higher than the usual maximum of 20 m for an S-type tubular turbine, special thrust bearings and a water-lubricated radial bearing have been designed. An emergency braking system has been designed for the higher torque. The turbine has been designed to allow setting above tailwater level and to operate under a head variation and variable speed within the cavitation characteristic limits. The project is scheduled for further field trials in 1988.

ii) Development of a Darrieus Type Vertical Axis Hydraulic Turbine (VAHT)

Since 1979, the Hydraulics Laboratory of the National Research Council has carried out model testing and field testing to develop a Darrieus type hydraulic turbine capable of extracting kenetic energy from fast river and tidal currents.

The VAHT is also suited to an ultra-low head application (less than 2 m) where higher velocities through the machine may be achieved. The turbine could be installed in an opening of an existing low dam, or at a flow regulating gate.

From late 1986 to the spring of 1987, Nova Energy Limited (NEL) of Nova Scotia was funded to carry out the design, construction and field trials of a 5 kW floating free-stream system [NEL, 1987]. The complete turbine assembly is mounted on the stern of a 5.5 m (18 ft) fibre glass boat. The rotor blades can be folded into the frame once it is retracted over the boat. This allows the unit to be trailored, then launched in shallow water, towed to the site and moored, before the turbine blades are deployed.

Preliminary tests were carried out at a tidal river site in Halifax County, Nova Scotia. The tests showed that all systems, including the rotor shaft, brake and bearings, operate satisfactorily. The rotor operated smoothly with little of the characteristic torque ripple and no negative torque. More intensive performance tests are being carried out.

iii) Improvement of a Very Small Micro-Hydro Unit (less than 5 kW):

There are very few commercial products available for a residential size power system at a remote off-grid location where small or seasonal streams cannot supply even 5 kW continuously. Energy Systems and Design of New Brunswick has been manufacturing and marketing world-wide several models of versatile and low price units since 1984 [ES&D, 1986].

One such model, Powerhouse Paul's Model Permag-T-1 is available for Can. $1000 and can produce up to 2 kW. The machine combines a Turgo or Pelton-type runner directly connected to a permanent magnet alternator and can be used over a very broad range of heads- from one metre to 200 metres. The turbine can use up to four 25 mm diameter nozzles with an overall machine efficiency of over 50 per cent. Output can be rectified to DC for battery charging. The turbine runner, nozzles and housing are made of polyurethane and Lexan^{TM}R polycarbonate casting. These materials have high tensile strength and abrasion resistance.

The current R&D project is attempting to improve the existing design by developing a full-admission type to replace the multi-nozzle type and by developing a lower cost, smaller and lighter weight, high frequency permanent-magnet-rotor alternator.

b) Generator and Controls

i) Medium and Low-Power Generator for Hydro Application

Concordia University, Montreal, with R. Nair Associates is developing and improving the Swinging Field Synchronous Generator (SFSG) for hydro, tidal or wind power application. SFSG has no rotating field windings or brushgear, and generally can have a higher inherent inertia. It should be more reliable and require less maintenance. It is suitable for both traditional constant speed running and also variable speed, "stand-alone" or "grid" operation.

Basic development areas are aimed at reducing weight and cost, improving waveform, and adapting missile industry experience with high frequency SFSGs.

c) Development of A Computer Aided Design (CAD) System for Small and Low-Head Hydro Turbine

Ecole Polytechnique, University of Montreal, is carrying out the development of a CAD system for small hydro industry to model, simulate and analyze hydraulic turbines. The software programs would be used to help the designer find solutions to potential problems in order to improve the performance of turbines. Using the software the engineer could test new designs by varying the parameters within the program and thus new turbines could be quickly developed. It could save considerable time and effort required for the traditional method of testing and modifying scaled-down models.

Details of this project are described in the paper "From Inlet to Outlet: Turbo Machines" presented by R. Comerero and B. Ozell at this Conference.

d) Innovative Civil Works and Components Projects

i) Evaluation of Syphon Performance Using an Hydraulic Model:

Since an appreciable cost advantage could be realized by using a syphon instead of a conventional intake for small-hydro installations at existing dams, a research study was awarded to Acres International Ltd. to investigate and establish criteria for the intake geometry, submergence and the performance of syphon by a laboratory installation [Acres, 1987].

ii) Design of Low-Cost Flowthrough Rockfill Dams and Spillways

This research work is being carried out by the University of Ottawa, Ontario. The primary goal of this study is to produce a manual for the design of flow through rockfill dams. Many such dams have been built in countries such as Australia and South Africa, but few have been built in North America. A low-head rockfill dam with a built-in "flow-through" spillway section capable of handling the design flood could lead to a significant cost reduction as compared with concrete spillway and dams. The application of this technique could be particularly advantageous for remote northern sites where the cost of concrete works is very high.

e) Tidal Energy Related R&D

i) Tidal Power and Canada -- A Review

During the past two decades there have been several intensive studies of the technical and economic feasibility of the exploitation of the energy of the Bay of Fundy tides. Recently a consultant report has been prepared [Clark, 1987]. This report (i) summarizes the developments to date on tidal power activities world wide, (ii) reviews recent engineering investigations of the Bay of Fundy potential, and (iii) identifies the principal technical and environmental issues still requiring resolution.

There are two additional projects which are closely related to a Fundy tidal power development. These are:

ii) Development of Hydrodynamic Model in Cumberland Basin for Tidal Power Application [Acadia, 1987]

This is a state-of-the-art computer simulation model of the tide and current movements in the upper Bay of Fundy, where the world's highest tides occur. The simulation with three-dimensional analysis reproduces the drying of mudflats and the generation of whirlpools and other complex current patterns associated with the very large tides in the Bay of Fundy. As part of this research, a preliminary investigation was made of the physical impacts of a tidal power dam proposed for the Cumberland Basin, by simulating the operation of a tidal power plant and examining the effects on tidal circulation in the area.

iii) Assessment of Viability of Retiming Cyclic Power from Bay of Fundy

Tidal energy would have a significantly enhanced value if its natural cyclic energy could be economically retimed to a firm supply which would serve as the equivalent of additional dependable capacity. A contract was awarded to Canadian Atlantic Power Group Inc. to examine the economic feasibility of retiming cyclic power using compressed air energy storage (CAES) for a proposed tidal power plant in the Bay of Fundy. The project is to develop prefeasibility level costs and construction schedules based on a conceptual arrangement of an air compressor and generating plant and an evaluation of underground storage facilities, and to examine briefly the economic implications.

iv) Ultra-Low-Head Approach to Tidal Power

The concept of an ultra-low-head approach to tidal power has been put forward [Simons, 1984]. This concept involves a "tidal fence," analogous to a bridge across high velocity tidal currents in a deep channel. It may be applicable to some sites in Canada and elsewhere with low tidal amplitudes but high flows. These sites will not be attractive for development with "conventional" tidal schemes. The large vertical axis Darrieus turbines could be used with this concept. However, its engineering detail, technology, performance and economic feasibility remain to be determined [Highquest, 1985].

5.2 DEMONSTRATION PROGRAM

Under federal-provincial cost-sharing programs, more than 20 small-hydro demonstration projects have been completed since 1980. They range in size from 2 kW to 2.5 MW. The purpose of the demonstration initiative was to establish the financial and commercial viability of small hydro while generating industrial activity and putting some technical innovations into practice.

In Ontario, the Canada/Ontario Small Hydro Demonstration Program has provided financial support totalling almost $800K as capital cost contributions to seven projects having a total generating capacity of 1366 kW. The average contribution level to these projects was 33 per cent, with total investment costs reaching about $2.4 million. The seven project proponents included two municipal utilities, a conservation authority, a private non-profit organization, an operating flour mill and two tourist mills. The capital cost for these projects ranged from $750 to $2800 per KW, and the project rates of return were estimated at 13 to 25 per cent after the grant compared to 8-17 percent before the grant.

There are six demonstration projects in B.C. and one in the Yukon. They are associated with the tourism, small industrial and agricultural sectors. The 75 kW micro hydro project at the Tidal Rush Marine Fish Farm on Vancouver Island is the latest project completed with federal demonstration assistance. EMR contributed $30,000 out of a total cost of $155,000.

In Québec, four submersible turbo-generator units were installed at two retrofitted mini-hydro dams of the City of Coaticook. A 1 MW low head hydro plant was built and commissioned at the remote community of Wemindji, near James Bay. Recently, two other projects have been approved, including a 2.1 MW mini-hydro installation at Côte-St-Catherine along the St. Lawrence Seaway.

Under the Remote Community Demonstration Program (RCDP) 19 small hydro feasibility studies have been carried out across Canada. One project has already been constructed in B.C. at Moses Inlet by private industry and another project at Mary's Harbour, Labrador has been completed recently by a private utility with an EMR funding contribution.

Innovative features and cost-cutting measures of the Ontario demonstration projects are listed in Table 1 [SNC, 1985]. From those more than 20 demonstration and other projects across the country, major technical aspects demonstrated can be summarized as follows:

Table 1

Canada/Ontario Small-Hydro Demonstration Program Projects 1983-85

PROJECTS	INNOVATIVE FEATURES	COST-CUTTING MEASURES
PETERBOROUGH PUMPHOUSE	-Reuse of existing turbine with minimal refurbishment costs -Installation of power transformer in the middle of the pumphouse with a view to utilizing losses for heating of the room	-Reuse of existing turbine -Use smaller generator

PROJECTS	INNOVATIVE FEATURES	COST-CUTTING MEASURES
FANSHAWE DAM	-Maximal use of existing storage dam features, existing discharge tube was coupled to the steel penstock -"Armco" steel culvert for draft tube and tailrace channel -Largest induction generator used for hydraulic power generation in Ontario	-No penstock butterfly valve installed -Tailrace/draft tube well of prefabricated corrugated steel
KINSMEN PARK	-Use of "second-hand" 300 m long plastic pipe -Single pair of wires with solid-state multiplexer for transmission of five water levels -Precast concrete blocks instead of gabions for channel wall protection	-Penstock installed by floating upstream on head pond, then drawn into trench by pulling over wooden rollers -Precast concrete blocks made in local plant and used to stabilize tailrace banks instead of gabions -Monorail carried on wooden collar ties in "A" frame powerhouse
ELORA MILL	-Gravity close on inlet butterfly valve -Self-cleaning trash rock incorporated with dam crest -Penstock arrangements to protect riverside of mill	-Elbow draft tube installed in existing natural rock cut -Equipment installed and serviced by portable crane -Access to powerhouse compromised for economy
WILSON'S MILL	-Use of two turbines in tandem with one generator	-Reuse of existing turbines
THORNBURY DAM	-Sharing of water usage with fish lock	-Reuse of existing structures
BRANTFORD P.U.C.	-Use of siphon for turbine flow control -Turbine runner set above water level -Priming of siphon by reversed air blower	-Siphon type setting eliminates additional flow control -Use of gabions for tailrace wall -Larger generator used rather than adding thermal sensors to smaller unit

a) Prefabricated Turbine and Generating Equipment Packages

Several commercial turbine packages have been selected on the demonstration projects. These include "L" turbines, S-tubular, submersible "Flygt", crossflow, "Hydrolec", Pelton and others. The factory-built and tested packaged units are compact enough for easy shipping to the site, and can be quickly installed. This concept is opening up new potential for low-head hydro in remote locations. Another "water to wire" self-contained system, "Mini-Hydel," features a complete hydro-generating facility enclosed in a tubular powerhouse which can be transported and installed in one piece.

b) Innovative Civil Structure Arrangement and Construction

The first syphon penstock for small hydro at an existing dam in North America was installed at Wasdell Falls, Ontario. Another configuration using an "inverted intake siphon system has been developed and the turbine was placed at the top of a siphon loop across the dam and the intake is headed downward. This is an inexpensive system that could be easily retro-fitted to low-head dams and irrigation canals.

The use of existing dam features was demonstrated. One major feature is the use of existing flow discharge tube at the dam as a turbine penstock. At Shand Dam of Grand River, Ontario, a 800 kW mini-hydro station was built in 1986 on one of the buttresses of the dam using the existing low-flow valve and pipe for the penstock and control valve.

Polyethylene, fiberglass and PVC material for penstock has been installed in Newfoundland, Ontario, B.C. and other provinces. Use of local material and skills for construction of the dam (i.e. rock-filled timber crib dam), use of prefab powerhouse building and other simplified construction and installation techniques have been encouraged through demonstration activities.

c) Standardized Electrical Generation Equipment and Automatic Control

A British Columbia firm has been maufacturing a series of highly advanced, standardized small hydro control equipment. It provides electronic load control governors, load managing, frequency monitoring, and protection panel accessories. By application of modern electronics, the cost of small hydro plants is reduced and their design and efficiency improved.

d) Annapolis Low Head Turbine Demonstration

On May 2, 1984 North America's first tidal power plant began producing power at Annapolis Royal, Nova Scotia, in the Bay of Fundy. it demonstrated the operation of the world's largest straight-flow turbine (7.6 m) with rim-mounted generator [STRAFLO].

The 20 MW output plant produces approximately 50 GWh annual energy and its rated head is 5.5 m. The Federal Government contributed $25 million toward total project costs of $60 million. Because the modern Straflo turbines can be applied at the low-head sites up to 40 m, its compact layout can provide significant cost savings in civil structure over the vertical propeller units. Innovative powerhouse and intake design, shop pre-assembly of large pieces of turbine-generator equipment, automatic operation and remote control, and other features have been demonstrated at this landmark project. After four years satisfactory operation, this project could improve the economics of harnessing low-head river hydro resources in Canada and enhance prospects for development of major tidal power sites in the upper reaches of the Bay of Fundy.

5.3 TECHNOLOGY AND INFORMATION TRANSFER

The Renewable Energy program is devoting more resources to its information and technology transfer activities. This seems particularly important for this technology which already has many commercial applications. EMR has prepared a "Small Hydropower Handbook" for British Columbia, and for Newfoundland and Labrador. This small hydro design manual is available to the public and will give the developers some guidance for their project assessment and implementaion. A Canadian small hydro newsletter is now being published. In addition, a small hydro industry directory is being prepared.

Several small hydro conferences and workshops have been sponsored by EMR for the last several years. The course "Small Hydro Project Development in Canada" was held and well attended earlier this week at this Conference. The course notes will be published by EMR as a guide to the Canadian small hydro developers.

6. OUTLOOK AND CONCLUSION

Although hydro power is a mature technology, significant improvements in small and low-head hydro equipment design, construction and operation are being accomplished through research, development and demonstration. With the need to refurbish old small hydro plants, and the desire of small remote communities, individuals, and developing countries to use small hydro, a tremendous market demand is emerging for efficient small turbines, for low-cost and reliable hydraulic kinetic energy conversion devices, new small generators, innovative solid state load controllers and remote control operation devices.

The general philosophy behind our Renewable Energy initiatives is that government assistance is required to allow a new industry to develop their products to the stage of commercial readiness. This approach is based on the premise that market forces will act effectively to determine the appropriate level of commercial activity. Federal government of Canada will continue limited support on research, development and demonstration activities up to the point where market forces can take over.

Recently my Branch has entered into an agreement with the Canadian Electrical Association to work collaboratively on developing energy systems suited for the remote and northern areas of Canada. This agreement is particularly significant since it allows us to work closely with Canadian utilities in developing such technologies as small hydro to move into the mainstream of energy in Canada.

As mentioned earlier we have put a higher priority on the effective transfer of information between our programs and the industry. We already have a Technical Advisory Committee made up of private sector representatives who give us technical advice and direction. We also receive advice on overall program direction from our Steering Committee on Research and Development, again composed of mostly private sector people.

We are also working closely with several provinces such as Ontario on small hydro development to ensure that our respective programs are complementary. In this way the limited resources available to our respective organizations can be used cooperatively for the greatest, most positive effect.

I believe that the future for renewable energy in Canada is indeed a bright one. Technologies such as small hydro, which are very near to full commercialization, give us many examples of what can, and will be done with Canadian experience and ingenuity. Given the technical, economic and environmental benefits of small hydro technology both in Canada and abroad, the support by Energy Mines and Resources will hopefully provide the final push to fully realize these benefits.

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Trenton Dam #1

By
G. Steeves

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TRENTON P.U.C. POWER PROJECT

[1]George Steeves, P. Eng.

GENERAL BACKGROUND

The City of Trenton is complemented by the Trent-Severn Waterway which flows into the Bay of Quinte within the city limits. The Trent-Severn Waterway is a canal used for recreational boating. Originally constructed in 1915 for commerce, the canal has numerous dams which have been utilized by neighbouring municipalities and by Ontario Hydro for electric power generation. The first dam on the 12400 km^2 (4800 mi^2) system is in the City and the headpond is presently used for the intake to the municipal water supply. Before the canal was built, electric power was generated at a dam near the same site. That original plant, built by the Bush Electric Lighting Company, was dismantled but the remains of the headrace are visible between the west end of the dam and the canal. The current dam is 150 metres (500 ft.) wide and retains a head of 3 metres (10 ft.).

The City of Trenton distributes and sells electricity with its own Public Utilities Commission, an organization which is regulated under the provincial Power Corporation Act. All energy is purchased from Ontario Hydro to serve the 8,000 residents. In 1982, a developer proposed that the P.U.C. should generate its own power at Dam No. 1. Subsequently the P.U.C. initiated the requisite studies and negotiation which has advanced the project to the final approval stage.

RECONNAISSANCE, PRE-FEASIBILITY

Although Dam No. 1 is an existing structure on a heavily developed watershed, the initial studies revealed not only an economic small hydropower site, but also a very complex approval process.

The structure is owned by the Federal government; power generation is regulated by the provincial utility, Ontario Hydro; recreational use is intense including both fishing and navigation and as a result the many interests of federal and provincial agencies must be considered.

The successful operation of the many sites upstream, in conjunction with the concepts proposed for development, verified that the site had economic and technical merit. Consequently, the P.U.C. was advised to conduct feasibility studies.

FEASIBILITY STAGE

A feasibility study which addressed technical, environmental and social implications of the development was completed. Since the dam is existing, has large overflow capacity, and is well maintained, the technical viability was never in question. However, the multifacetted regulatory system and the many recreational users of the site were the focal point of analysis.

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There is a myriad of different pieces of legislation, regulations and policies that control small hydropower in Ontario. The development process is further complicated by having the receive approvals from both federal and provincial government agencies. Figure 3 illustrates the approval process for all relevant legislation. This figure is set in priority legislation and identifies what has to be completed first. It also demonstrates the interaction of the federal and provincial legislation.

Unfortunately everything is not as clear cut as the small hydro power developer or government agencies would like with often overlapping legislation. Such was the case with the Trenton Dam No. 1 project.

Parks Canada owns and operates the dam. As the approving agency for the project under the Federal Environment Assessment Review Program (FEARP) their concerns were related to both administration, operation activities and also to environmental concerns.

Currently the dam is operated on a seasonal basis with two distinct operating regimes. During the winter months the stoplogs in several of the sluices are removed to pass the generally higher flows with the resultant reduction in headpond water levels. An operating benefit with this regime is the elimination of stoplog adjustments during freezing weather when they can be tedious and costly.

During the May to October navigation period the logs are reinstalled with the headpond level increased.

The potential environmental impacts of the project therefore result from two sources:

(1) Firstly, the impact of maintaining the winter headpond water levels at the same elevaiton as the summer levels.

(2) Secondly, the impact of the potential redistribution of the flow regime across the width of the dam.

Parks Canada had specific technical concerns which were and are being addressed. These included:

(i) The provision of heated stoplog gains to facilitate the operation of the dam in the winter and maintain its ability to pass flood flows.

(ii) The provision of a power operated gate with a standby power source which would automatically open on the loss of the plant from service to compensate for the plant flow.

(iii) development of an operating heirarchy and plant control logic process addressing their concerns.

Other users of the waterway could be affected by such a project. However, the feasibility study identified only areas of minimal impact. For example, there is no potential for power development downstream, flows which normally passed over the dam will still be discharged directly into the main river channel; upstream users such as Ontario Hydro will be minimally affected, if at all, by higher tailwater due to higher winter levels at Dam No. 1.

The primary concern was the environmental effect of the redistribution of flows in the immediate vicinity of the dam. Parks Canada requested attention to the concerns of the Ontario Ministry of Natural Resources, fisheries biologist, and the Ontario Ministry of the Environment. As a result a summary of questions was prepared:

- Will present flow rates vary permanently or during construction?
- Will flows vary in location or time of discharge across the dam and will this adversely affect the fish communities?
- Will biological requirements be considered during low flow?
- Will the new installation consider aesthetics and the historical nature of the waterway?
- Will navigation be affected?
- Will public safety be addressed?

In response to the questions raised during the Feasibility stage, and following the confirmation that the FEARP was required, additional environmental studies were commissioned.

IMPLEMENTATION

During the initiation of the FEARP process, the P.U.C. met with several potential developers. One of those proposed to obtain approvals and to build the site as a turnkey developer/owner. The site would then be managed and maintained by the developers in return for a long term contract.

APPROVALS

The FEARP process continued under the original criteria identified in the Feasibility study. Concurrent with the ongoing FEARP work, the Ontario Ministry of the Environment exempted the project from the provincial Environmental Assessment Act.

There are three possible levels of detail which may be required:

- Environmental Screening
- Initial Environmental Evaluation
- Environmental Impact Statement

The Screening, which is normally based on existing data, was deemed appropriate. However, additional information was required because the existing data was not sufficient. The general approach to screening is shown in Figure 1. During the study the list of contacts and topics which were addressed included:

Contacts:

Parks Canada, Environment Canada (Water Survey of Canada), Ontario Ministry of Natural Resources, Ontario Ministry of the Environment, Ontario Ministry of Energy, Lower Trent Region Conservation Authority, City of Trenton, Ontario Hydro.

Topics:

Flow regime, fish habitat, dam operation.

The preliminary exchange of information among approval agencies resulted in the need to review alternative powerhouse locations along the dam length. To model the effect of alternative powerhouse locations on the distribution of flow during the fish spawning season, stoplogs were removed from each proposed location.

Flow in the test day was typical of the spring. Because it is difficult to get a clear view of the currents from shore, a helicopter was used to permit videotaping from directly overhead. This tape was used to demonstrate conditions similar to plant operation to the concerned agencies. As a result the recommended powerhouse location was changed. The FEARP Environmental Screening made several recommendations:

- That a monitoring programme be maintained during construction and the first year of operation.

- That monitoring involve Parks Canada, (owner of the site) the Ministry of Natural Resources.

- That regulatory agencies review construction drawings prior to commencement of work.

- That access be provided around powerhouse as presently exists along the dam for fishermen.

Environmental Screening concluded with a public open house. Displays included a model of the dam with powerhouse, conceptual drawings, hydrologic data and an area for the public to comment on the project. The open house was advertised in local papers and invitations were sent to fishing and hunting clubs and other potentially interested clubs. Final approval of the Environmental Screening is now pending.

CONCLUSION

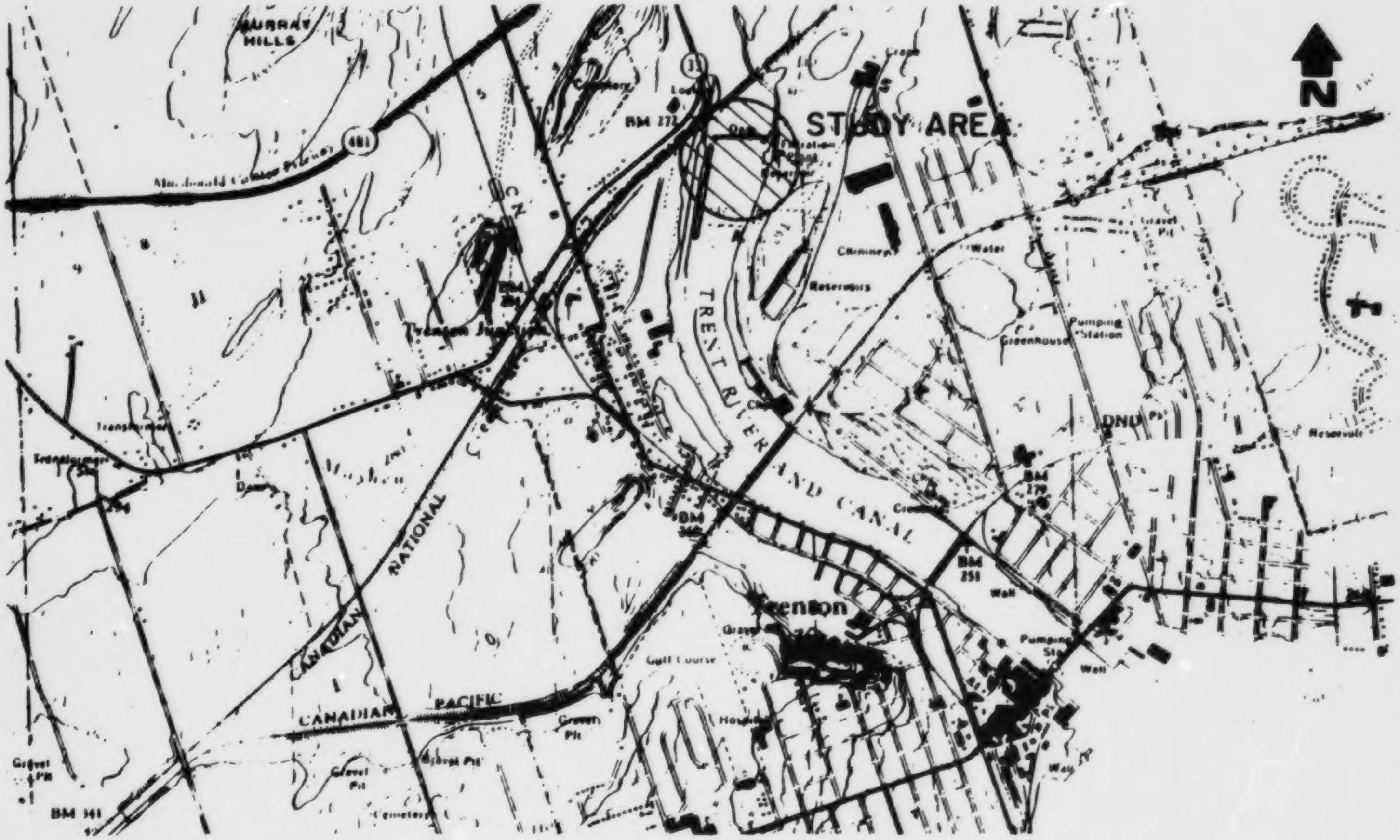
The Trenton Small Hydro Project has been a precedent setting exercise for recent Ontario Projects. New generating stations have not been constructed on the Trent Severn Waterway for many years. Final construction of the plant is optimistically expected to begin in late 1988 with commissioning in 1989.

The progress of work to this stage is a credit to the tenacity of the City, the prospective developer and the regulatory agencies who have continued to contribute to the project through many changes in concept and methodology.

SMALL HYDRO '88

TRENTON DAM NO. 1

CUMMING COCKBURN LIMITED


N
MURRAY HILLS
401
33
STUDY AREA
BM 272
C N
Chimney
Reservoirs
Water
Greenhouse
Pumping Station
DND
Reservoir
TRENT RIVER AND CANAL
BM 279
BM 251
BM 260
Trenton
Golf Course
Wall
Pumping Stn
CANADIAN NATIONAL
CANADIAN PACIFIC
Gravel Pit
Cemetery
BM 161
Transformer

A- VELOCITY CROSS-SECTION

LOCATION PLAN

SCALE 1:50000

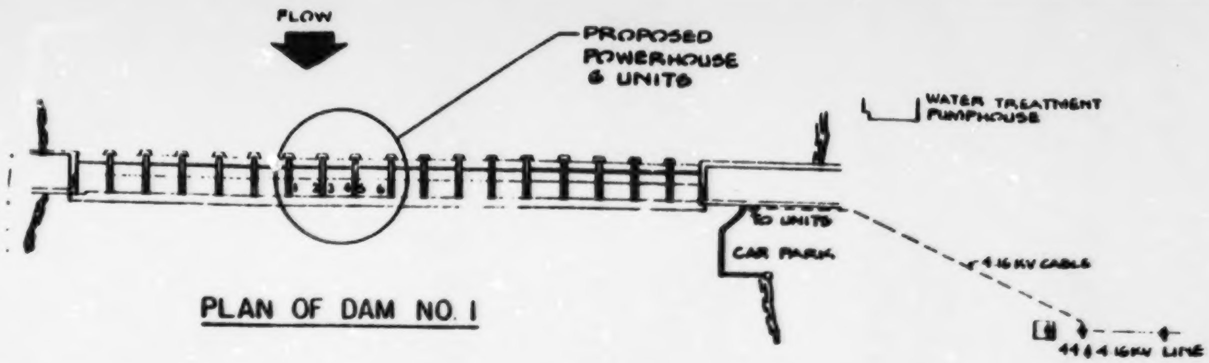
FIGURE 2

PYSICAL FACTORS

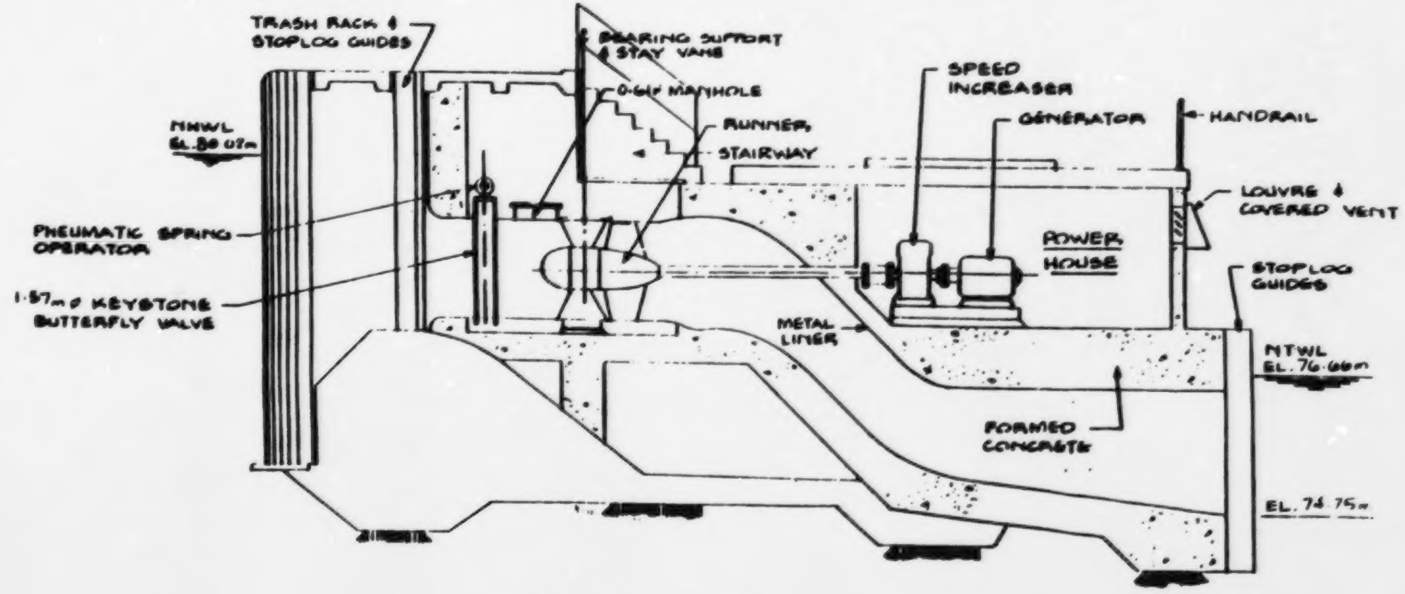
- 12,400 SQ. KM
- REGULATED WATERSHED
- 150 METRE WIDE DAM
- 18 SLUICE WAYS
- 3 METRES OF HEAD

PROPOSED DEVELOPMENT

- 6 UNITS SINGLE REGULATED HORIZONTAL TUBULAR TURBINES
- EACH TURBINE HAS A RATED CAPACITY OF 225 KW FOR A TOTAL DEVELOPMENT CAPACITY OF 1350 KW
- VERY LOW PROFILE POWERHOUSE
- TRASH RACKS
- BUTTERFLY VALVE
- CONNECTED TO P.U.C. GRID


FLOW
PROPOSED POWERHOUSE 6 UNITS
WATER TREATMENT PUMPHOUSE
TO UNITS
CAR PARK
4.16 KV CABLE
44 ϕ 4.16 KV LINE

PLAN OF DAM NO. 1

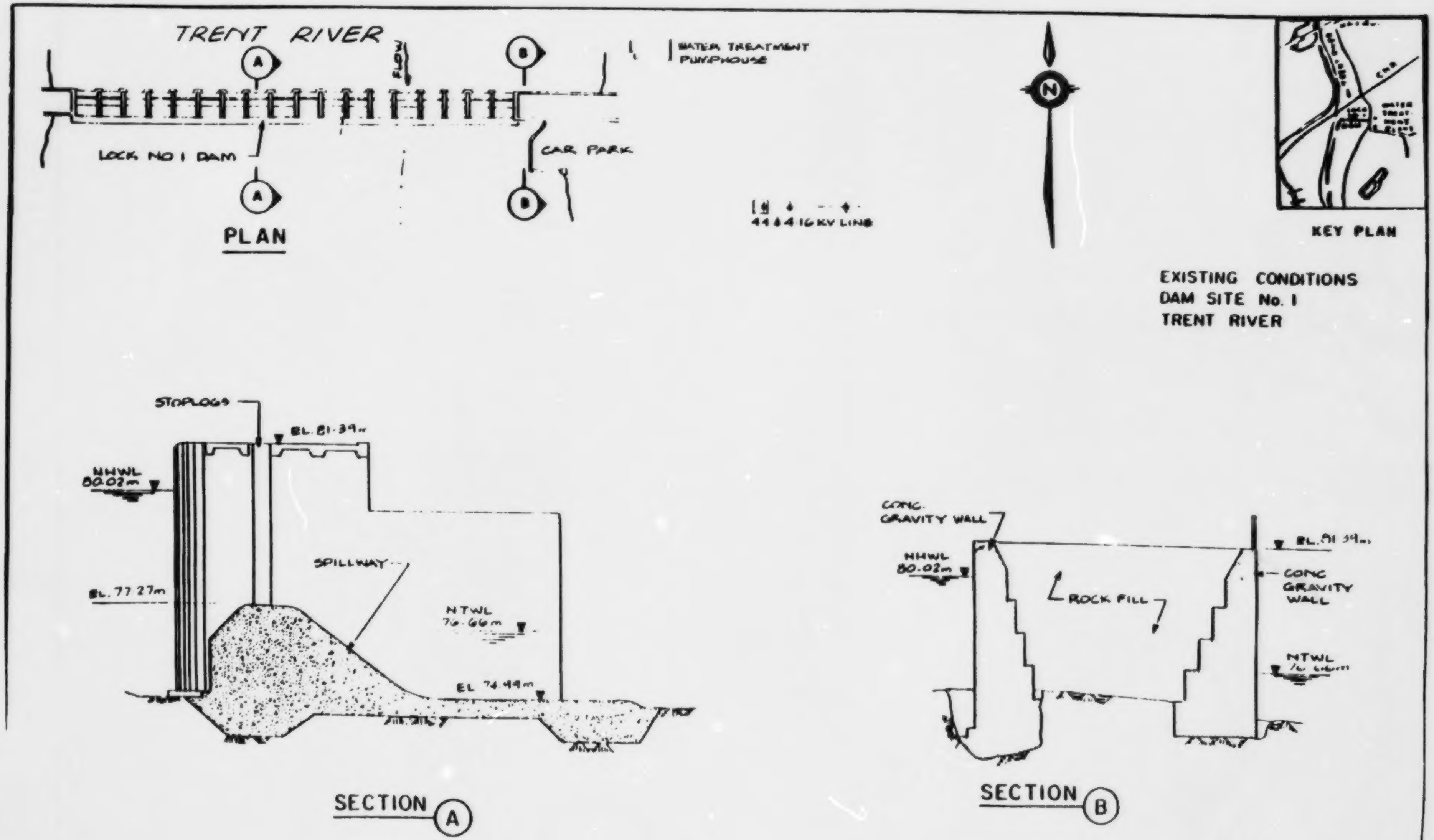

TRASH RACK & STOPLOG GUIDES
BEARING SUPPORT & STAY VANE
0.61 ϕ MANHOLE
RUNNER
STAIRWAY
SPEED INCREASER
GENERATOR
HANDRAIL
NHWL EL. 80.07m
PNEUMATIC SPRING OPERATOR
1.57m ϕ KEYSTONE BUTTERFLY VALVE
LOUVRE & COVERED VENT
POWER HOUSE
STOPLOG GUIDES
METAL LINER
NTWL EL. 76.66m
FORMED CONCRETE
EL. 74.75m

SECTIONAL ELEVATION

CCL

PROPOSED SMALL HYDRO ELECTRIC
GENERATING STATION
DAM SITE No 1
TRENT RIVER

FIGURE 4


TRENT RIVER
FLOW
A
B
WATER TREATMENT PUMPHOUSE
LOCK NO 1 DAM
CAR PARK
44 & 4.16 KV LINE
PLAN
N
KEY PLAN
STOPLOGS
EL. 81·39m
NHWL 80.02m
EL. 77.27m
SPILLWAY
NTWL 76·66m
EL 74.49m
SECTION A
CONC. GRAVITY WALL
NHWL 80.02m
EL. 81.39m
ROCK FILL
CONC GRAVITY WALL
NTWL 76.66m
SECTION B

EXISTING CONDITIONS
DAM SITE No. 1
TRENT RIVER

FIGURE 3

PROJECT IMPACTS

- INCREASED WINTER HEADPOND WATER LEVELS
- REDISTRIBUTION OF FLOW REGIME ACROSS THE WIDTH OF THE DAM

INCREASED HEADPOND WATER LEVELS

CONCERNS

- WINTER OPERATION OF STOP LOGS FOR WATER LEVEL REGULATION
- OPERATING HEIRARCHY

RESOLUTIONS

- PROVIDE HEATED GAINS
- PROVIDE POWER OPERATED GATE
- PROVIDE OPERATING PROGRAM AND PLANT CONTROL LOGIC

REDISTRIBUTION OF FLOW REGIME ACROSS THE WIDTH OF THE DAM

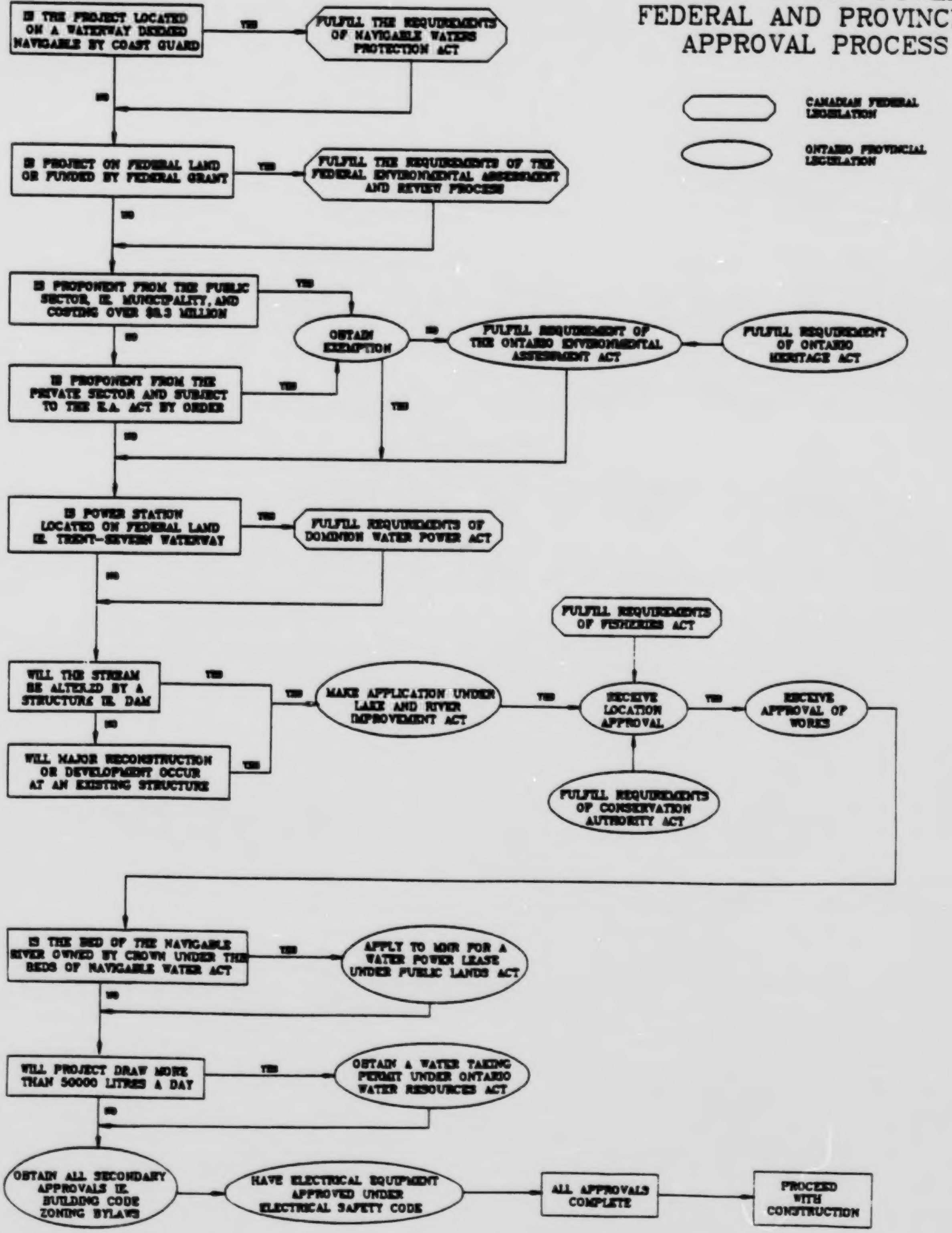
CONCERNS

- WILL PRESENT FLOW RATES VARY PERMANENTLY OR DURING CONSTRUCTION
- WILL FLOW VARY IN LOCATION OR TIME OF DISCHARGE AND WILL THIS ADVERSELY AFFECT THE FISH COMMUNITIES
- WILL BIOLOGICAL REQUIREMENTS BE CONSIDERED DURING LOW FLOW
- WILL HISTORICAL AND AESTHETIC NATURE OF THE WATERWAY BE ADDRESSED
- WILL NAVIGATION BE AFFECTED
- WILL PUBLIC SAFETY BE ADDRESSED

RESOLUTION

- FEDERAL ENVIRONMENTAL ASSESSMENT AND REVIEW PROCESS

ONTARIO'S SMALL HYDRO POWER FEDERAL AND PROVINCIAL APPROVAL PROCESS

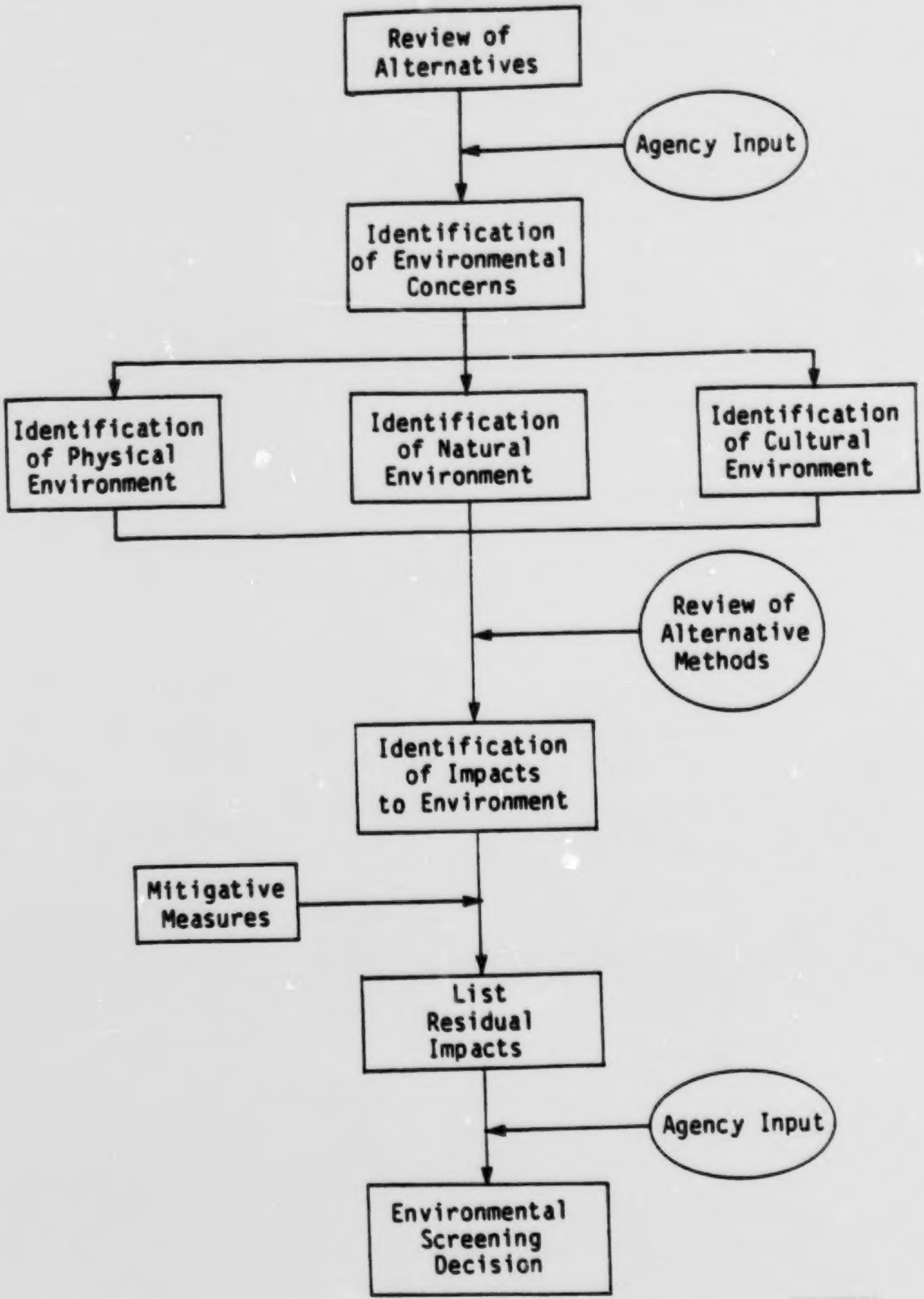

CANADIAN FEDERAL LEGISLATION
ONTARIO PROVINCIAL LEGISLATION
IS THE PROJECT LOCATED ON A WATERWAY DEEMED NAVIGABLE BY COAST GUARD
YES
FULFILL THE REQUIREMENTS OF NAVIGABLE WATERS PROTECTION ACT
NO
IS PROJECT ON FEDERAL LAND OR FUNDED BY FEDERAL GRANT
YES
FULFILL THE REQUIREMENTS OF THE FEDERAL ENVIRONMENTAL ASSESSMENT AND REVIEW PROCESS
NO
IS PROPONENT FROM THE PUBLIC SECTOR, IE. MUNICIPALITY, AND COSTING OVER $2.3 MILLION
YES
NO
OBTAIN EXEMPTION
NO
FULFILL REQUIREMENT OF THE ONTARIO ENVIRONMENTAL ASSESSMENT ACT
FULFILL REQUIREMENT OF ONTARIO HERITAGE ACT
IS PROPONENT FROM THE PRIVATE SECTOR AND SUBJECT TO THE E.A. ACT BY ORDER
YES
YES
NO
IS POWER STATION LOCATED ON FEDERAL LAND IE. TRENT-SEVERN WATERWAY
YES
FULFILL REQUIREMENTS OF DOMINION WATER POWER ACT
NO
FULFILL REQUIREMENTS OF FISHERIES ACT
WILL THE STREAM BE ALTERED BY A STRUCTURE IE. DAM
YES
YES
MAKE APPLICATION UNDER LAKE AND RIVER IMPROVEMENT ACT
YES
RECEIVE LOCATION APPROVAL
YES
RECEIVE APPROVAL OF WORKS
NO
WILL MAJOR RECONSTRUCTION OR DEVELOPMENT OCCUR AT AN EXISTING STRUCTURE
YES
FULFILL REQUIREMENTS OF CONSERVATION AUTHORITY ACT
IS THE BED OF THE NAVIGABLE RIVER OWNED BY CROWN UNDER THE BEDS OF NAVIGABLE WATER ACT
YES
APPLY TO MNR FOR A WATER POWER LEASE UNDER PUBLIC LANDS ACT
NO
WILL PROJECT DRAW MORE THAN 50000 LITRES A DAY
YES
OBTAIN A WATER TAKING PERMIT UNDER ONTARIO WATER RESOURCES ACT
NO
OBTAIN ALL SECONDARY APPROVALS IE. BUILDING CODE ZONING BYLAWS
HAVE ELECTRICAL EQUIPMENT APPROVED UNDER ELECTRICAL SAFETY CODE
ALL APPROVALS COMPLETE
PROCEED WITH CONSTRUCTION

Cumming Cockburn Limited
Consulting Engineers and Planners

FIGURE 1

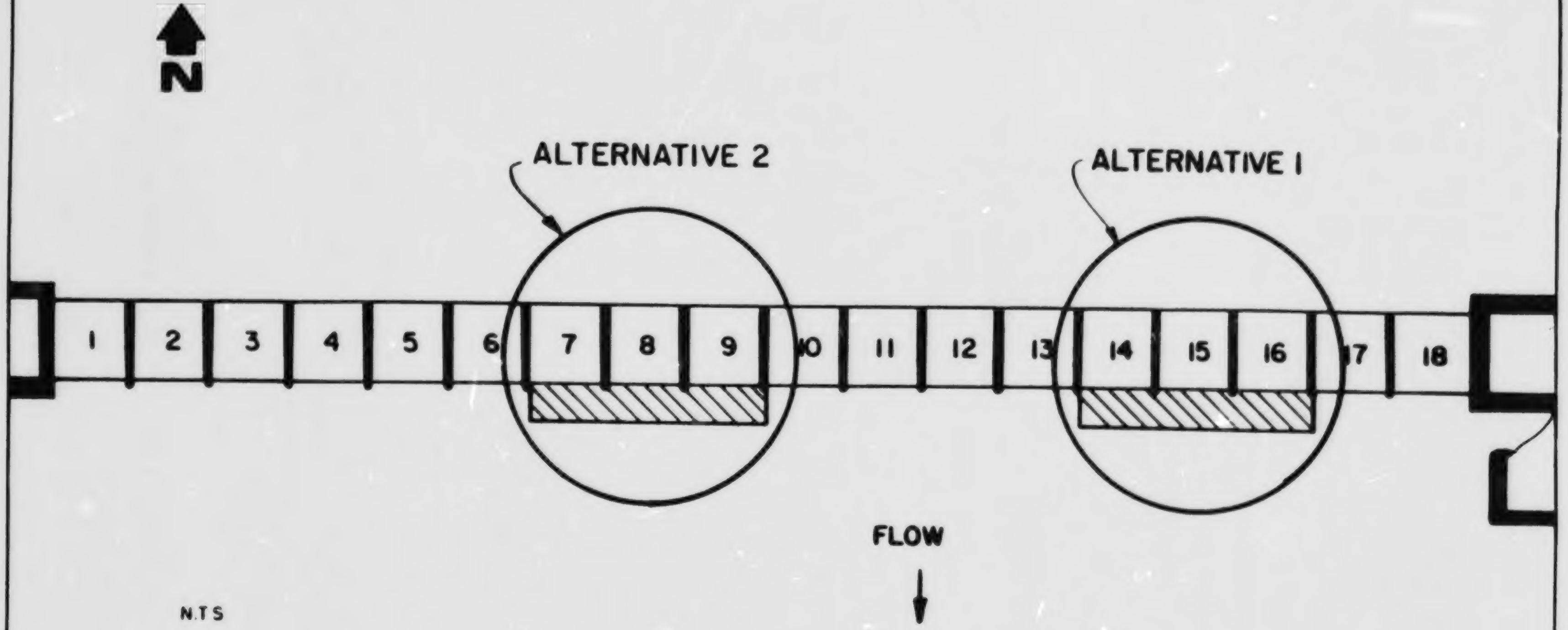
HOW WAS THIS ACCOMPLISHED

- BACKGROUND RESEARCH
- FIELD PROGRAM
- PRELIMINARY SCREENING REPORT
- PUBLIC OPEN HOUSE & ADVERTISING


Review of Alternatives
Agency Input
Identification of Environmental Concerns
Identification of Physical Environment
Identification of Natural Environment
Identification of Cultural Environment
Review of Alternative Methods
Identification of Impacts to Environment
Mitigative Measures
List Residual Impacts
Agency Input
Environmental Screening Decision

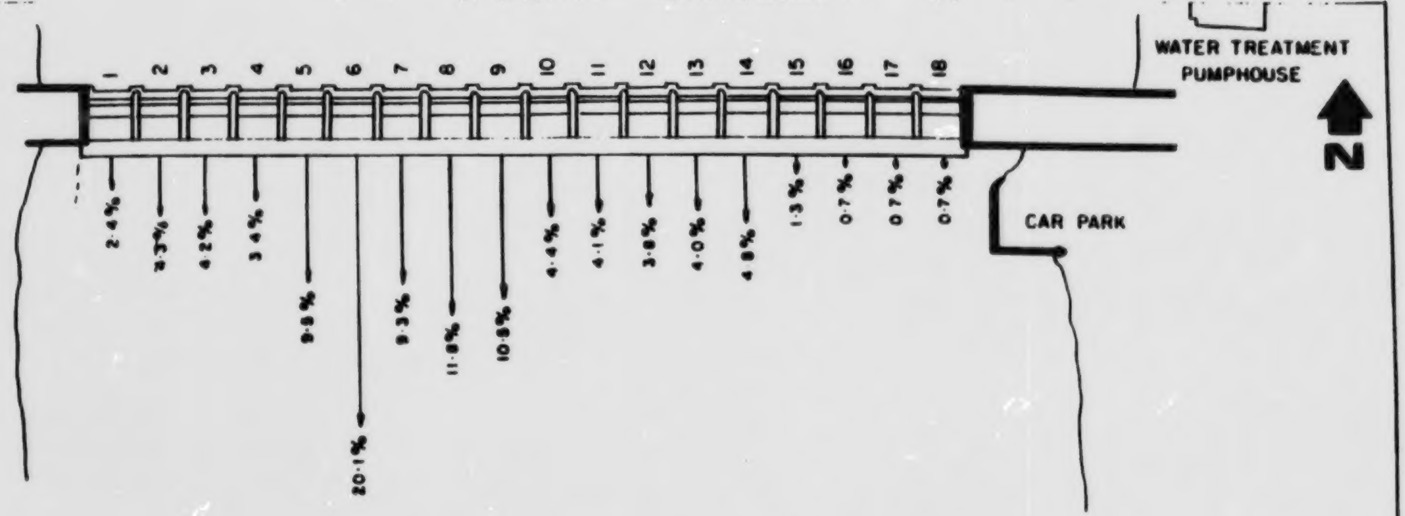
GENERAL APPROACH TO ENVIRONMENTAL SCREENING

FIGURE 1


N
ALTERNATIVE 2
ALTERNATIVE 1
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
FLOW
N.T.S

ALTERNATIVE POWERHOUSE
LOCATIONS FOR A SMALL
HYDROELECTRIC GENERATING
STATION-DAM #1
TRENT RIVER

FIGURE 7


1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
2·4%
2·3%
4·2%
3·4%
9·8%
20·1%
9·3%
11·8%
10·8%
4·4%
4·1%
3·8%
4·0%
4·8%
1·3%
0·7%
0·7%
0·7%
WATER TREATMENT
PUMPHOUSE
N
CAR PARK

SCALE OF FLOW ARROWS : 1:5

THE PERCENT FLOWS ARE WEIGHTED AVERAGES FOR EACH MONTH, AVERAGED OVER THE RESPECTIVE YEAR. THE PERIOD OF RECORD FOR STOP LOGS 1982 - 1985 INCLUSIVE AND THE FINAL FIGURES (ABOVE) ARE AVERAGES OF THESE FOUR YEARS

ALTERNATIVE I

6 8 % OF THE TOTAL FLOW PASSES THROUGH BAYS # 14, 15, 16

ALTERNATIVE 2

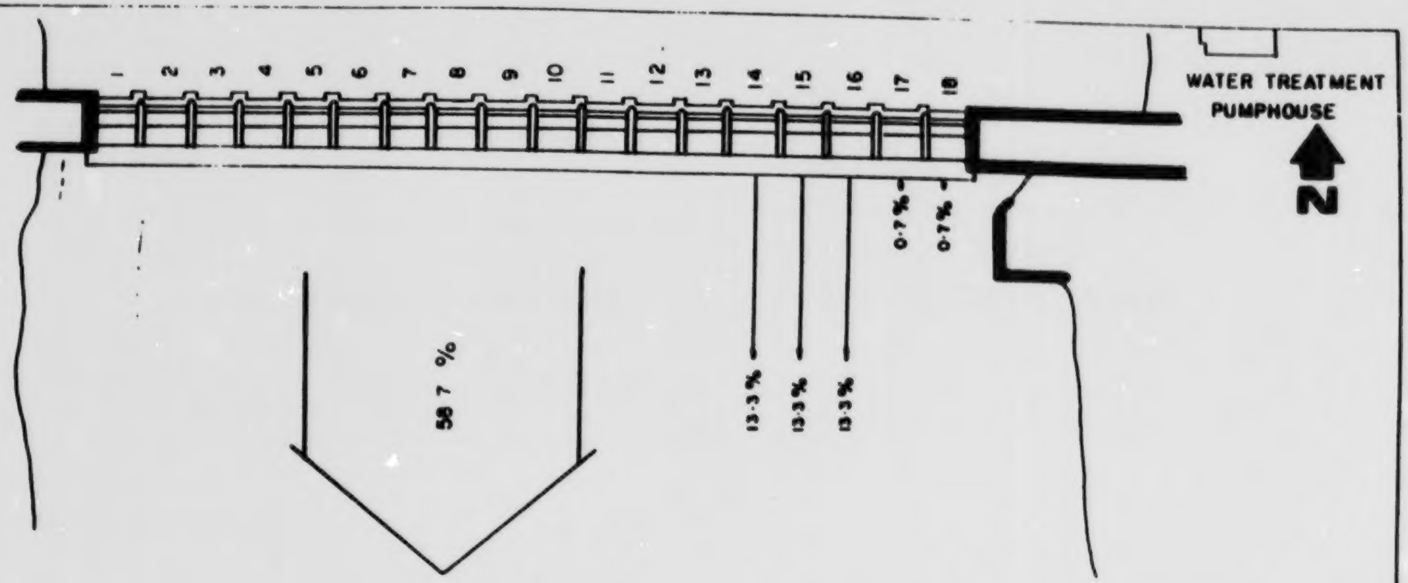
31 6 % OF THE TOTAL FLOW PASSES THROUGH BAYS # 7, 8, 9.

ANNUAL MEAN FLOW 142 CMS

PERIOD OF RECORD FOR FLOW: 1923 - 1945; 1964 - 1985

EXISTING CONDITIONS AVERAGE YEARLY PERCENT FLOWS THROUGH DAM # I ON THE TRENT RIVER

FIGURE 12


WATER TREATMENT
PUMPHOUSE
N
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
58 7 %
13·3%
13·3%
13·3%
0·7%
0·7%

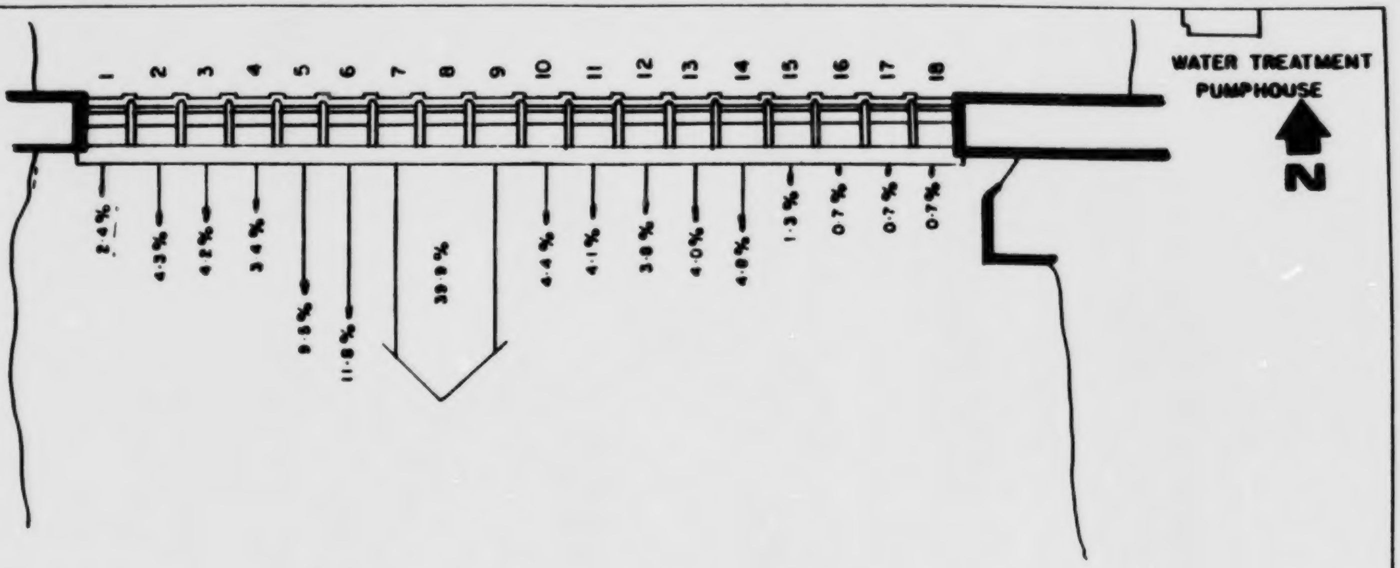
MEAN YEARLY FLOW - 142 CMS
PROJECTED FLOWS THROUGH
REST OF DAM :

BAYS #14, 15, 16: 56·6 CMS (39·9%)

SCALE OF FLOW ARROWS 1:5

TRENT DAM #1
FUTURE CONDITIONS
OF DAM OPERATION
DURING MEAN
ANNUAL FLOW
ALTERNATIVE I

FIGURE 13



WATER TREATMENT
PUMPHOUSE
N
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
2.4%
4.3%
4.2%
3.4%
9.8%
11.8%
39.9%
4.4%
4.1%
3.8%
4.0%
4.0%
1.3%
0.7%
0.7%
0.7%

MEAN YEARLY FLOW — 142 CMS
PROJECTED FLOWS THROUGH
REST OF DAM :

BAYS # 7, 8, 9 : 56.6 CMS (39.9%)

SCALE OF FLOW ARROWS 1:5

TRENT DAM #1
FUTURE CONDITIONS
OF DAM OPERATION
DURING MEAN
ANNUAL FLOW
ALTERNATIVE 2

FIGURE 14

SCHEDULE

ORIGINAL STUDIES	1985
PRELIMINARY ENVIRONMENTAL WORK	SPRING 1986
START OF FEARP PROCESS	FALL 1986
SUBMISSION OF FINAL ENVIRONMENTAL SCREENING REPORT	FEB. 1987
OPEN HOUSE	FEB. 1988
FINAL APPROVAL	PENDING

Hydro Electric Power Stations on Man-Made Canals in Pakistan

By
M.Y. Akhtar

22

HDRO-ELECTRIC POWER STATION
ON
MAN-MADE CANALS
IN PAKISTAN

by

PROF. M.Y. AKHTAR
JOINT DIRECTOR
NATIONAL INSTITUTE OF POWER
GOVERNMENT OF PAKISTAN
MINISTRY OF SCIENCE AND TECHNOLOGY

14-C1, Gulberg-111
Lahore-11
Pakistan

HYDRO-ELECTRIC POWER STATION ON MAN-MADE CANALS IN PAKISTAN

BY: PROF.DR.M.Y.AKHTAR.

SYNOPSIS.

Nature has blessed this country with lot of water resources which plans in rivers out of which canals have been taken out for irrigation purposes and making the biggest canal net-work in the world, The natural gradient of land is much more than that needed for the man-made canals, which is optimised for the quality of water having slit and the nature of the bed. In the presence of such high natural gradients, the canals have been given falls varying from 2 to 10 ft. depending upon the site conditions after every 1000 to 2000 ft. and different means have been adopted on the falls to dissipate the extra kinetic energy imparted in the water. To utilise this potential energy of the water available to generate electricity, there are certain limitations i.e. no storage capacity and in the presence of variable electrical load, the speed of generator fluctuates, thus creating disturbaces in the canal flow, which is completely undesirable. Electronic controls have been used and tested, which produce lot of harmonics in the supply making the alternator unfit for the supply of induction machinery. For this purpose, eddy current brake has been developed and used for loading the generator shaft to fixed load and sharing the power between the brake and the alternator, thus wasting the extra energy in the eddy current brake. The applications of such advice is limited upto 50 KW capacity. In order to over come this dumping of extra energy and using a higher capacity machines, variable blade angle speed control has been developed, which incorporates a small 6V DC Series Motor with an electronic dircuitory to watch for the frequency with a given reference, sothat the electrical energy be generated as per requirements without allowing the water to be stored in the canal:

1. INTRODUCTION.

Run-off hydel stations are normally installed on the man-made canals whose gadients are optimised according to the silt contents in the flowing water and the hardness of the canal bed & banks. Pakistan has a very large net-work of such man-made canals. Nature has blessed this country with a land having a steeper natural gradient than required for man-made canals. In order to match the canal gradient with the land, for smooth flow in fields a fall varying from 2 to 10 ft. is made after every 1000 to 2000 ft., where the kinetic energy is killed by different means. The first blessing in disquise came up in 1945 when a difference in bed levels of a man-made canal (Upper Jehlum) and river Jehlum at Rasul was found 81 ft. and consequently 20 MW power station was comminiioned in 1948. Since such canals are made for irrigation purposes the water released has to be kept steady whether the electricty is generated or not. Under variable electrical load conditions, the mechanical power demand varies resulting in variations in the speed, which has been explained in reference 1 and this has been the main problem through out the world for the development of micro hydel/mini hydel at run-off sites. The existing practice has been to miniaturize the control of high capacity machines which obviously has limit of becoming uneconomical for small capacity machines. A step towards the solution has been taken with some success as reported in reference 2 and eddy current braking has been used for a 30 KW hydel stations having impulse turbine (X-flow banki). Realising its limitations, another solution has been found and by applying this a 50 KW hydel station has been made operational in Pakistan.

2. POWER PROTENTIAL.

In Pakistan, a large net-work of man-made canal is available for which the canals have been taken out from rivers by constructing barrages. Such barrages raise the water level to match the irrigation requirements and consists of many falls for which WAPDA has worked out about 900 MW. The maximum unit capacity is about 2 MW at an rmp of about 150-200 because the water head varies from 8 to 10 ft. and the cost of conventional machinery and construction shall force us to shelve this project. Furthermore, there are big link canals which have be made under Indus Basis Treaty and the power potential from all the canals shall aggregate to about a thousand megawat or so. So far about 40 MW at three sites has been availed where three falls were integrated and a total head was made to 22 ft. with retaining walls about 10,000 ft. long. Such plants shall be economical if operated at base load otherwise serious problems shall come into being.

3. FREQUENCY CONTROL THROUGH BALLAST.

Fig.1 shows the general arrangements for this type of control. The turbine generates a fixed mechanical power to run the alternator at a constant output otherwise the variable load on the alternator shall create problems by creating water heading and over flowing the banks, so the alternator operates at a steady load. The electronic controller is equipped with thyristors which are triggered at different angles to by-pass the extra power, thus producing a non-sinusoidal wave form which has plenty of harmonics and rendered the alternator output unfit for induction machimery.

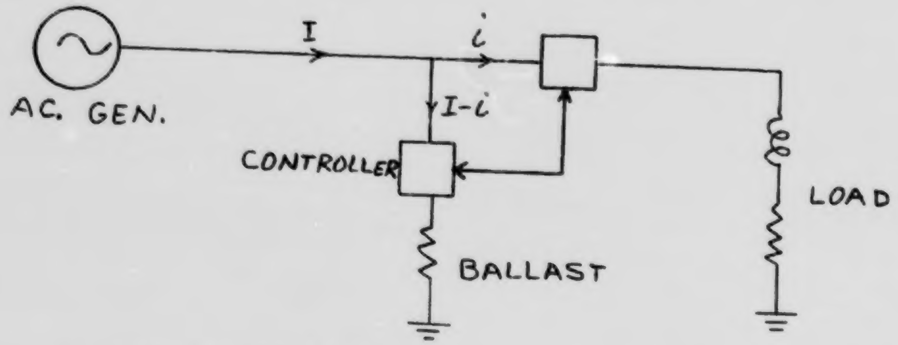


Fig.1 Showing the use of ballast to divert the surplus current.

4. EDDY CURRENT BRAKING.

The basic principle of eddy current braking is shown in fig.2, where a copper disc moves in a megneric field. The eddy currents are induced in the disc which exerts electro machanical forces on the disc elements. This type of arrangment is already in use for checking, the brake horse power of motors. In the present setup, the copper disc is replaced by high conductivity steel cylinder to get eddy currents and simultaneously reducing the magnetic reluctance.

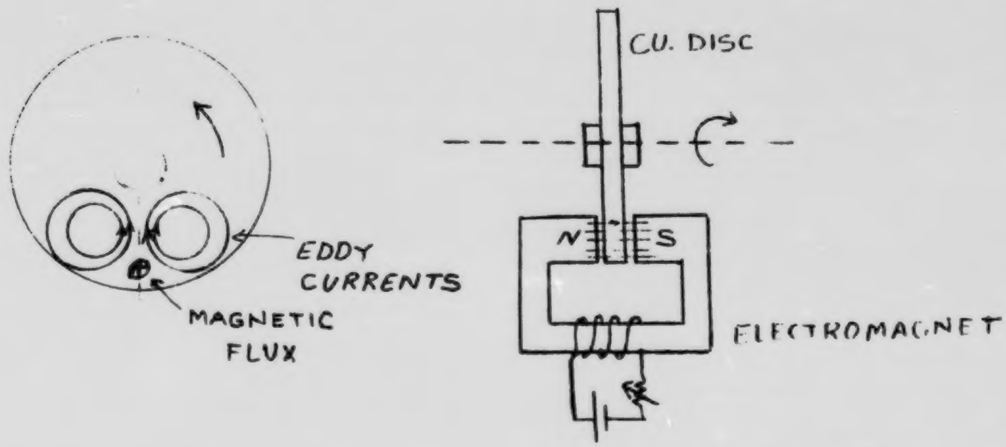


Fig.2 Showing the principles of eddy current braking.

The general arrangement is shown in fig. 3 in which the exciting current is provided by the main alternator varies directly with (I-i), when co-ordinated with the load on the generator shaft shall be maintained constant, thus the stator winding of the alternator does not supply the extra power and the turbine shaft runs at a fixed load i.e. the alternater supplies the power as required by the load and the extra mechanical energy of the turbine shaft shall be used in eddy current braking.

5. BLADE ANGLE CONTROL.

In both the above frequency control methods mentioned at 3&4 wastes power in the form of heat & electro mechanical forces, for which dissipation is a problem and it puts the limitations on the capacity of the machine. For bigger units, the turbine should generate the required power and by-pass the extra water so that irrigation requirments be met without disturbance.

Considering the quality of the skill available in common workshops, mechanical arrangement has been adopted through gears which is much more economical as compared to the hydraulic system. For a four blade turbine unit the gear arrangements is shown in fig.4.

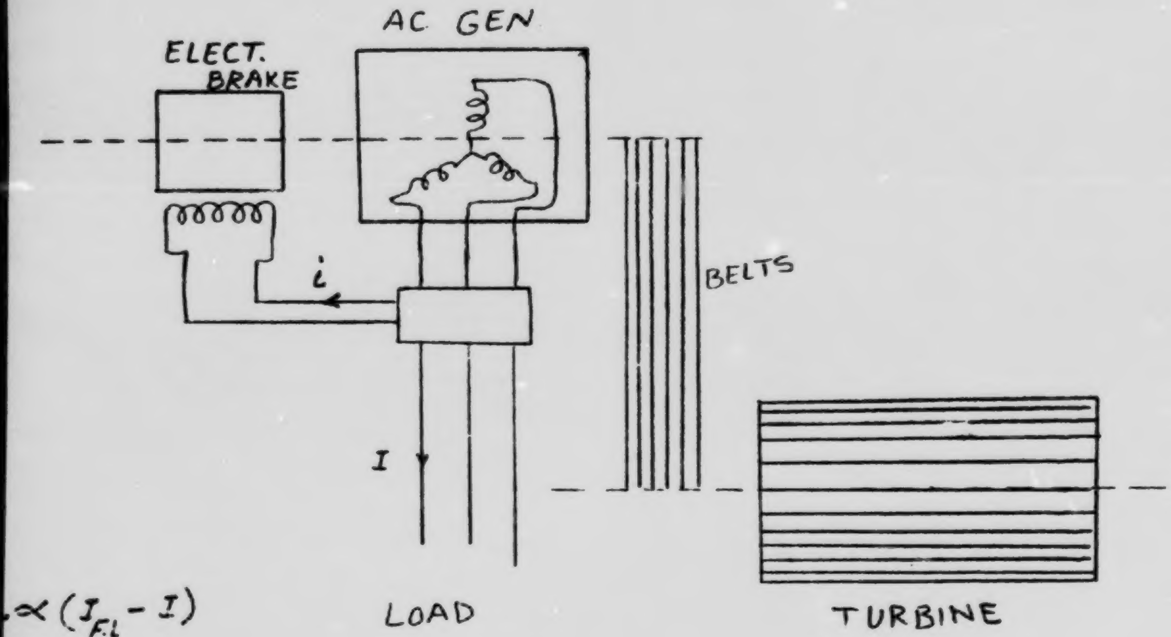


Fig.3. overall arrangements for the application of eddy current braking.

The locking of blades has been achieved through worm & worm wheels of a very large ration of 2000. The driving motor a 60 Watt, 6 Volt, DC Series Motor fixed inside the hub. The motor is controlled with electronic circuitory incorporating a frequency counter to operate the motor in one direction or the other. Different slides shall show the different views.

6. NECESSITY OF A BY-PASS.

Canals are made to allow the water up to certain discharge and to avoid heading, the water not permitted to flow through the turbine has be allowed to pass on after due killing of its kinetic energy. For this purpose two by-passes with fins inside to kill kinetic energy have been used with sufficient area to allow the full water to flow in case the turbine does not allow the water to flow. The function of these by-passes is identical to the fundtion of a spill way in a bigger hydel stations with dam.

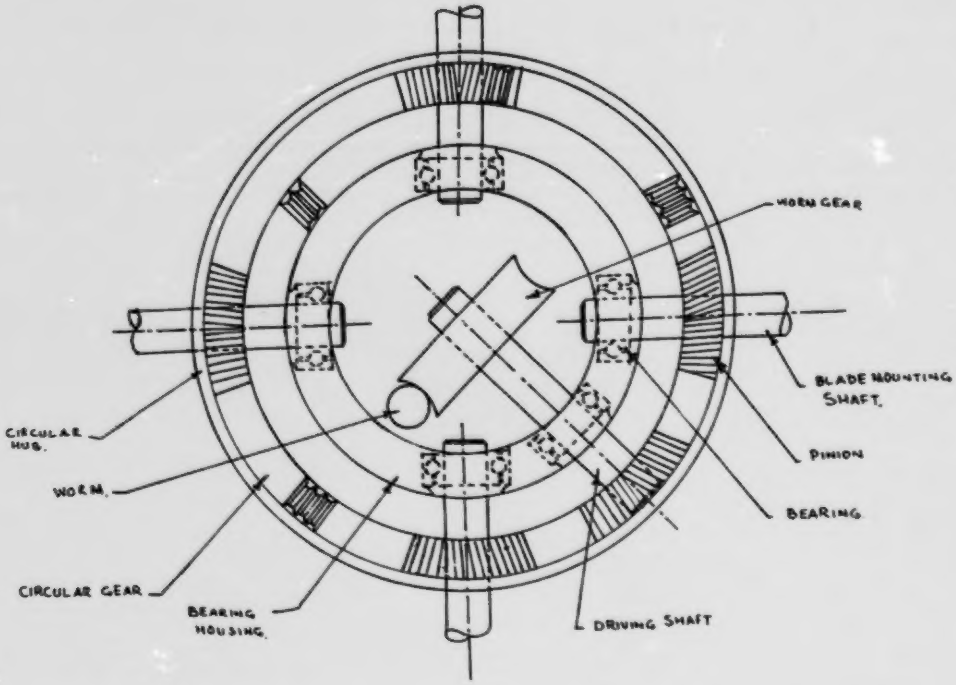

WORM GEAR
BLADE MOUNTING SHAFT.
PINION
BEARING
DRIVING SHAFT
BEARING HOUSING.
CIRCULAR GEAR
WORM.
CIRCULAR HUB.

Fig.4. Gear arrangements for blade angle control.

7. CONCLUSIONS.

A 50 KW hydel station on the man-made canals has been made operational at a cost about 5450 KW by avoiding the expensive civil works normally required for conventional construction. It shall help the developing countries to accelerate their programmes for electric power generation.

8. ACKNOWLEDGEMENT.

The author is indebted to Mr.S.A.Niazi, General Manager, Hydel WAPDA for his encouragements.

9. REFERENCES.

1. Runner, S.S & L.leerman, "Energy" Vol.1, Addison Wesley Publishing Co. 1981.

2. Maria Elna Hurtado & Essam El-Hinnawi "Hydro Power" Daily Muslim 8th January, 1983.

*A*U/*

SESSION 19:

SMALL HYDRO PLANNING ' B'

Chairperson: K. Bennett
Ottawa Engineering

Criteria for the Design of Small Hydro in Developing Countries

By
M. Estrada

23

CRITERIA FOR
SMALL HYDRO DESIGN
IN
DEVELOPING AREAS

by

MARINO ESTRADA
Escuela Colombiana de Ingenieria
Bogata, Columbia

CRITERIA FOR SMALL HYDRO DESIGN IN DEVELOPING AREAS

MARINO ESTRADA
Escuela Colombiana de Ingeniería - Bogotá, Colombia

The author feels that in order to have a more realistic presentation, analysis and open discussion of some topics, is preferable to use the terminology of DEVELOPED and UNDERDEVELOPED AREAS, instead of Developed and Developing Countries, avoiding unnecessary frictions and unwelcome suspicions. He would like to thank your understanding in allowing this change.

INTRODUCTION

The design of a Hydro Station, even if it is small, is normally the result of an adequate balance and analysis of a very complex set of relationships of numerous factors, very often contradictory or opposed, leading sometimes into a compromise. Therefore what it could be considered an excellent design for some given conditions, could not be considered so for somewhat or greatly different conditions.

Some of the factors to be considered are:

1) REQUIREMENTS.- Maximum power demand, load curve and factor, total energy consumption, rate of grow of power and energy, use of the power and energy, quality of the service; voltage and frecuency variations allowed; importance of the uninterrupted service; interconnected or isolated generation.

2) NATURAL CONDITIONS.- Hydrological; flow duration curves, Q95, Q50, normal and extraordinary floods, distribution through out the year. Topographical and Geological conditions.

3) DESIGN CONSIDERATIONS.- Type of development, storage or run-of-river. Dimensioning of structures for adequacy, safety, Codes of practice, State of the art, Legal regulations, Environmental restrictions or considerations. Transportation, construction, erection and maintenance facilities or limitations. Operating conditions and personnel. Expected life of the utility. Changes of conditions for future operation or enlargement. Available funds.

4) SPECIAL LOCAL CONDITIONS.- Use of local resources, development or promoting local industries.

As it can be easily understood, all these factors varies from place to place and for the same place within the time, that is to say with their degree of development.

The purpose of this paper is to review the criteria for designing small hydro stations, being used at present; specifically when those stations are located in underdeveloped areas, after analysing many of the aspects which have a big influence on the design.

DEVELOPED AND UNDERDEVELOPED AREAS

With reference to small hydro, the differences between developed and underdeveloped areas are very numerous:

a) To start with, their definition of what is a small hydro station, up to 15000 Kws for developed areas; up to 5000 Kws for developing areas.

b) Their Geographical location: northern hemisphere for developed, tropical or subtropical for developing. This different location results in different Hydrological, Topographical and Geological natural conditions.

c) The Kws/person installed: (2.5 for developed, and less than 0.2 for underdeveloped). The Kwshr./habit/year: above 8000 for developed, less than 1500 for developing.

d) Mostly interconnected for developed; many isolated stations or even lack of them for some areas in underdeveloped.

e) The use of the energy: a combination of industrial, commercial and residencial, for developed areas, and mainly residential and street lighting for the other. The service being uninterrupted, continuous, with strong limitations for the frecuency and voltage oscillations in one case; and sometimes during only a few hours of the day, with ample variations of frecuency and voltage in the other. It is important to declare that, when an Industry (mineral, cement, paper) is located in underdeveloped surroundings, is considered as developed.

f) The purpose of construction: mainly to save or economize non-renewable resources in one case, and to be the only source of electric power supply in the other. Better regulation by having a power station at the end of a long transmission line.

g) The per capita income: above 8000 US$/per cap/year in developed and less than 1500 US$/per capita/year for underdeveloped. This has a big influence in the capacity to pay for the energy consumption, and therefore affects the feasibility of some projects from economical considerations.

TYPES OF DEVELOPMENT

The type of development of a Small Hydro Station, is the classical one, corresponding to "run-of-river installation", consisting of:

a) Headworks

b) Regulating and desilting works

c) Conveyance structures (generally a canal)

d) Forebay and excess spillway and discharge canal

e) Penstock

f) Power house

g) Tailrace canal

MOUNTAINOUS RIVERS

The rivers of tropical or subtropical areas, when located at elevations ranging from 1500 to 3000 metres above sea level, are most useful for small hydro, when proper care is taken of their main characteristics, which are: mountainous or semi-mountainous rivers, with a bed slope over 15 metres per kilometre, the water has a velocity from 2 to 4 mts/sec; their specific flow is quite high, over 50 lts/sec/Km2, having flows over 5 cumecs with relatively small catchment basins and reaching up to 25 cumecs with a ratio larger than 400:1 for the Q of floods to the Q95. They tansport mainly a bed load of sand and small gravel, for normal flows, but can reach high velocities and very rapid floods, when they transport big boulders and rocks up to 1.5 metres in diametre, big trees, and some other debris which can fill up almost any type of intake. Even if intake structures and water diversion is one of the earliest activities of mankind, we have not reached a perfect design. Some of the weirs designed with undersluices which work very well in silty waters, can be rendered useless in a few hours of floods. The author has seen a big steel gate, destroyed by a rock of over 2 metres in diametre.

HEADWORKS

These could be of two types: Diversion Works or Storage Works. Diversion works are located across a river in order to raise the water level and divert a certain amount of water, into the canal. Storage Works, store the surplus water when in excess of demand, and increase the incoming flow during high demand.

TYPES OF DIVERSION WORKS

The diversion works could be:

Temporary: These are structures which may be destroyed or carried away during high floods, and can be very economical. Other weirs of the so called "INDIAN TYPE", can be very economical and are not so easily carried away by normal floods.

Permanent: In the permanent type of weirs, when the flow is less than 10 cumecs the bottom intake has been proven as one of the best and more economical type of intake for mountainous rivers, however, more detailed studies and experimentation is urgently required.

The solid spillway gravity dam of concrete, as the main weir, must have a part controlled by a gate, if it is rather narrow can be used for alluvial rivers, but require a carefull operation if a fill up during floods is to be avoided. Its main disadvantage for rivers with big bed load, is that it requires periodical cleaning, using heavy costly equipment.

The gated weir is used for small, medium and high capacity stations, it works very well for alluvial rivers and for large semi-mountainous rivers, but it is the most expensive, and require more personnel and additional safeguards for good functioning.

ENTRANCE AND CONTROL STRUCTURES

The entrance is located either at an angle or perpendicular to the diversion weir. There is normally a trashrack to stop the entrance of floating objects, debris, or large bed load into the canal. This trashrack must be cleaned and the operation may be mechanized, authomatized or manual.

To control the amount of water which passes into the canal, an excess spillway or a gate is used, in conjunction with a return canal or conduit.

DESILTING BASINS

In order to eliminate suspension materials, when the load is not heavy, the PARSHALL type of eliminator works well. Its main advantage being that require less area and excavation, therefore it must be used when there is rock or limitations in area.

For heavier material, sand and pea gravel, the Dufour III, sand eliminator works extremely well. It requires deeper excavation, and therefore occupies a larger area. A modification of this sand eliminator is the PANELED type, which includes the use of prefabricated panels of reinforced concrete.

CANALS

The mountain side slopes are sometimes quite steep, and are of rocky, residual soils, mainly clay, material, therefore there is not an strict need of lining the canal for impermeabilization. They are designed for higher velocities (around 2.5 mts/sec) than those recommended in canal design when alluvial rivers are considered or for irrigation canals. With such velocity the amount of excavation is less resulting in lower costs. It is true that the slope of the canal could be increased, decreasing the available head, but this is not as important as it is in the case of irrigation canals. There is need for lining only those portions where sandy, gravely or conglomerate is found.

FOREBAY

The forebay is a deposit or enlargement of the dimensions of the canal, at its end. It is required in order to avoid larga variations in the water level due to load changes. Its size depends more on the topographical conditions, costs, than on hydraulics requirements.

When the power plant is not generating, the excess water must be dispossed with, by means of some type of spillway. The bottom of the forebay cannot be flat, in order to avoid deposition of the suspended load. It would be desirable to have a slope from 3 to 5%, and should have proper means for the dispossal of the sediments, either by gates or a syphon spillway, connecting with the chute canal.

There is also an intake, of standard design, to connect the forebay with the power penstock. This intake must have: trashracks, control gate, and aeration duct for the penstock.

PENSTOCK

Formerly it was standard to have a penstock for each unit in the power house. Today a single penstock can feed various units, by using a manifold. The limit of the number of units being fed is a function of size, transport and economic considerations.

The material for the penstock is medium to high strength steel, welded not only in the factory but also in the field. The pipes are protected by using appropriate paints, after being cleaned by sand blasting.

The penstock is supported by using concrete saddles, and fixed by the use of anchorage blocks. Its design includes also some hydro stations (1000 to 2000 Kws), with heads from 40 to 60 metres, exising in Colombia have penstocks of reinforced concrete, with diametres around 0.6 metres.

POWER HOUSE

The power house for small hydro is of the external type. For small capacities a container could be used. About 50 or 60 years ago the use of two, normally three units, was the common practice. Today a single unit is preferable from economical and operational conditions.

The equipment to be used depends on whether the unit is interconnected or isolated, or is required to operate partially interconnected and partially isolated. If it is interconnected an induction generator, with even an ungoverned turbine, may be used. If it is to operate isolated or partially so, the generator must be of the synchronous type, with the turbine being regulated by a governor even of the PID type.

The author has seen various small units of small capacity (1 to 5 Mw) with an old governor out of service, working in an interconnected grid, without causing mayor difficulties or problems, so he advocates the use of a very elementary governor, P type or even manual regulation.

If the equipment is to work continously or almost so, there is no need for a valve, as the water can be controlled from the intake at the forebay when the ocasion araises.

As the size of the units increases, the governor must also be more advanced, and if the penstock is very large and or very long, the valve might be required.

A Francis turbine, having a higher specific speed, would be initially more economical than a Pelton turbine. However, is well known that at partial loading the former, efficiency falls down very rapidly, and furthermore there is cavitation and vibrations, and for a single runner side thust. In order to avoid this, two units might be recommended. A single generator with two Pelton wheels and two jets per wheel would result in a turbine with a very flat efficiency curve, with the possibility of using only two or three jets to adjust its power to the load. Of the four jets, two could be ungoverned, or with manual control, the other two being controlled by a governor. The buying price is higher, the generator could have lower RPM, being bigger, heavier and more costly, but the maintenance is quite easy. For easy and local maintenance and reparation the buckets should be detachable, manufactured of bronce. The same material could be used for the needle and nozzletip.

The bearings are water cooled. The water can be obtained directly from the penstock by means of a small pipe.

The generators are of the open air cooled type, with instrumentation to measure the temperature of the windings. The isolation level being normally H.

The generating voltage has been standardized at 3300 volts for units up to 5000 Kws; 6900 volts up to 8000 Kws and 13800 for larger units.

If the distance to the consummer is less than 3 kilometres, the station is isolated, the power can be transmited at the generated voltage, without a step-up substation.

If the station is interconnected it is required to introduce a step-up substation into the systems. In this case the power station can be started-up, controlled and shut-down by remote control from the interconnected centre.

The manufacturers have standardized many sizes of units, not only in generators but also in turbines, so very economical equipment can be bought today.

The cost of a small hydro station is from 3500 to 6500 US dollar per kilowatt installed, when all the structures and equipment is designed "under the actual practice and standards". At such a price it would be impossible to supply electric service to remote communities in underdeveloped areas. These communities are unfortunately those with the lower per capita income; from 100 to 300 dollars/per capita/per year. If their actual development correspond to that some communities in developed areas, at the end of the last century, could not we supply the former with electric power designed with standards which may seem outdated today?

Some of us have had the opportunity to operate, or visit these old stations, which after 50 or more years are still rendering a very good service and operating with very good results.

The author is not advocating the use of obsolete or "sloppy" engineering, but engineering at its maximum level; the one which supply "the real needs of the community using the available resources natural and local, at its maximum, in order to obtain the minimum cost; without endangering the human life, destroying property, all in accordance with a high regard for the environment".

OPERATING PERSONNEL

In developed areas the main factor is the high wages of operating personnel. This has led into the design of structures, equipments, and controls as automatic as possible, or at least the supervision be remote controlled or computarized. This practice and development requires a personnel which is scarse and oftenly unexisting in underdeveloped areas.

In underdeveloped areas the available personnel has very limited training to operate sophisticated equipment, but the wages are low.

Sometimes they are careless, and do not give proper attention to the work. Therefore the equipment for those areas must be as simple as possible, very rugged and easy to operate, maintain, and repair. Is that kind of equipment being manufactured today?

CONCLUSIONS

1. There are still many areas through out the world, without electric power service. Due to their remote location or the smallness of the community is sometimes uneconomical to built long transmission for that areas.

2. Some of these communities are located in areas with specially good natural conditions for the construction of small hydro stations.

3. The high costs of small hydro designed for conditions or according with standards alien to the area, make it impossible to supply those areas in the near future.

4. If the criteria for the design is changed, and equipment less sophisticated and rugged is designed and built, there would be a large market for it and the opportunity to supply those needs faster, with the same amount of available funds.

   This a challenge which confront all of us, engineers, designers, manufacturers, governments, and financial development institutions.

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Synthetic Hydrology Generation for Feasibility Level Evaluations of Small-Scale Hydro at Ungauged Sites in Ontario

By

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2

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FOR
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SYNTHETIC HYDROLOGY GENERATION FOR FEASIBILITY LEVEL EVALUATIONS OF SMALL-SCALE HYDRO AT UNGAUGED SITES IN ONTARIO

By

J. E. Anderson[1], E. T. Park[2], and B. I. McClennan[3]

The plant design and the economic return from a small-scale hydro project are very dependent on both the average streamflow and the pattern of the streamflow throughout the year. Consequently, feasibility level evaluations are best performed by simulating plant performance using a long period of streamflow record. Unfortunately, many potential sites are located at ungauged locations and synthetic streamflow records must be generated.

In recognition of this need, a study was undertaken by Acres International Limited for the Inland Waters Directorate of Environment Canada in 1987 - 1988. Two approaches to the generation of synthetic flow records were developed and compared. The first involves development of a flow duration curve based on regression analysis of curve characteristics against basin parameters. The second is more straightforward and develops a flow record by prorating the daily data from an index gauge based on drainage area and mean annual runoff. These methodologies have been incorporated into computer models which are now available for use in Ontario. The simulations use readily available data and generate a synthetic daily flow record that preserves the characteristics that would be anticipated in the historical record. The flows can then be used directly or converted to energy using part of the program package.

While this study focused on small-scale hydro, the hydrologic design methodologies which were developed have broader application. These procedures should also be of interest to those involved in water management activities such as water supply investigations for the municipal, industrial, agricultural and fishery sectors, water quality interpretive investigation, environmental impact assessment or any other activity where the streamflow magnitude and pattern are of interest.

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INTRODUCTION

Small-scale hydro potential is widely regarded as the most practical and viable renewable resource, in part, due to its mature technology.

Hydraulic variables such as available flow for electricity generation and its time distribution and flood magnitude, represent primary components of plant design and economic evaluation of potential hydro sites. Unfortunately, most small-scale sites are located on small ungauged streams. Estimating flow records at ungauged sites for benefit evaluation often pose technical difficulties, which cannot be resolved without an in-depth, site-specific hydrology study.

Selection of evaluation of site potential at the feasibility level is best carried out by simulating the operation of the hydro plant using a long period of streamflow record. While various techniques are available to generate such a record, they typically require considerable hydrologic judgment. In many cases, the cost of the hydrologic studies is a significant constraint to potential developers.

This paper provides an overview of a study undertaken in 1987-1988 by Acres International Limited for Environment Canada with financing through the Federal Panel on Energy Research and Development (PERD). The objective of the study was to develop step-by-step regional design methodologies which could be used to effectively and efficiently evaluate the low flow and average flow hydrology at potential ungauged small-scale hydro sites in Ontario.

Two regional methodologies for developing continuous streamflow records at ungauged sites were investigated and compared: a regression-based flow duration curve approach and a proration methodology based on an index gauge. The regression-based methodology, regresses the coefficients which describe a flow duration curve (dependent variables) against physiographic and climatic data (independent variables). The resulting flow duration curve at the ungauged site is then used with information at an index gauge as a basis for generating a synthetic daily flow record at the same site. Details are presented in the next section of this paper. The proration approach develops a daily flow record at a point of interest by prorating the daily flow record of an index gauge using the drainage area and estimating mean annual runoff (MAR) (i.e., flow volume) at the point of interest.

METHODOLOGY

Homogeneous Hydrological Regions in Ontario

Homogeneous regions were selected which exhibit similar low and average flow hydrologic characteristics within a basin. The homogeneous regions are shown in Figure 1. Regions for the regression-based methodology are defined as Regions A to F while the subset boundaries for the proration methodology are designated F1 to F8. A detailed explanation of the delineation of these regions can be found in Acres (1988).

It is important to recognize that the delineation of regions for the two approaches is quite different. By utilizing regional regression analyses for the flow duration methodology, the need to define homogeneous regions is reduced. The reason is that variability in the hydrologic characteristics from gauge to gauge will be explained by the independent variables included in the regression equation. Regionalization is therefore an attempt to account for factors which may be common to a region but which are not included in the regression analysis. In the limit, if all significant factors affecting average or low flows were anticipated and could be quantified, regional regression-based approaches would not require homogeneous regions to be specified.

On the other hand, when adopting a nonregression-based approach such as the proration methodology, where average hydrology is represented only by drainage area and MAR, there is a need to define a greater number of homogeneous regions to account for other factors affecting the discharge record.

The centroid of the basin of the site under consideration defines the homogeneous region of the site. In most cases, the regions were delineated to include whole basins; however, some exceptions occurred for the boundaries of Region A or between Regions E and F.

Synthetic Streamflow Generation

The general approach to developing regional relationships for the hydrologic parameters of interest has been an innovative application of traditional regional hydrological methods.

Having defined the homogeneous regions, it was necessary to select a set of gauges on which to basis the analysis. Gauge selection was based on the length and quality of record, size of drainage basin and spatial distribution with a region. A total of 120 gauges in regions A-F were used.

The two selected regional methods of synthesizing hydrologic records for ungauged sites are outlined below.

(a) Proration on Drainage Area and Mean Annual Runoff

The commonly used technique of proration based on the drainage area and mean annual runoff was evaluated.

The appropriate equation is

$$Q_{ijk} = QI_{ijk} \quad (A \quad MAR) \quad / \quad (AI \quad MARI) \tag{1}$$

where

i, j and k are the year, month and day respectively
Q is the discharge of interest (m^3/s)
QI is the index or nearest gauge discharge (m^3/s)
A, MAR is the drainage area, mean annual runoff of the location of interest respectively (mm)
AI, MARI is the drainage area, mean annual runoff of the index gauge or nearest gauge respectively (mm).

An index gauge was selected in each of regions A to F and in the eight subregions of region F. The index gauge in each case was based on the following criteria

- long period of continuous daily record
- quality of streamflow record at the gauge
- proximity to region centroid
- average or representative drainage basin area.

(b) Regression-Based Methodology

The regression-based methodology operates on the characteristics of a turbinable flow curve which is directly related to a flow duration curve as discussed below.

Turbinable flow is defined, herein, as the average discharge which can be passed through turbines for a particular design discharge (plant capacity). A turbinable flow curve describes the turbinable flow for a range of design discharges.

The probability density function of flows, the flow duration curve, and the turbinable flow curve are all uniquely related as shown in Figure 2.

The flow duration curve is expressed mathematically as

$$F(Q_d) = \int_{Qd}^{\infty} f(Q)\, dQ \qquad (2)$$

where

f(Q) is the probability density function of all daily flows
Q_d is the design discharge of the plant.

The shaded area under the flow duration curve represents the average discharge which can be passed through the turbines for a given design discharge, Q_d.

The turbinable flow which can be used with the average generation head to quickly evaluate the energy production at a site is calculated as

$$Q_t = \int_o^{Q_d} \int_{Q_d}^{\infty} f(Q)dQ \quad dQ \qquad (3)$$

It was found in previous Canadian regional hydrology studies that (Acres, 1984, 1986) that a 5-deg polynomial equation provided an excellent fit to the turbinable flow curve. The general forms of the 5-deg polynomial is

$$Q_T = \theta Q_D + \alpha Q_D^2 + \beta Q_D^3 + \gamma Q_D^4 + \kappa Q_D^5 \qquad (4)$$

By solving four simultaneous equations based on constraints imposed by boundary conditions (from hydroelectric generation criteria), it was only necessary to predict values for coefficients C, θ, and α to define the turbinable flow curve at an ungauged site. The remaining coefficients γ, β and κ are subsequently calculated from the simultaneous equations.

The coefficient C is the intercept of the flow duration curve on the discharge axis and reflects a discharge which is seldom exceeded. This coefficient therefore has a larger value for basins with little or no natural regulation compared with those which are more regulated.

Conversely, the coefficient θ is an indicator of the height of the knee of the flow duration curve and reflects the degree of natural regulation in a river basin.

It is difficult to interpret the physical significance of the coefficient α and hence the effects of basin characteristics on the calculated value of this coefficient.

In order that estimates can be made of the turbinable flow curve at ungauged sites, it is necessary to relate the coefficients of the polynomial equation to physiographic and/or climatic characteristics which can be measured in the ungauged basin. Physiographic characteristics included in the evaluation were drainage area, channel slope, percentage of area controlled by lakes and swamps, length of main channel, a basin shape factor and longitude and latitude. Hydrometeorologic characteristics included the base flow index, mean annual runoff, mean annual precipitation, and mean annual snowfall. A detailed description of the characteristics used in the regression analysis is provided in Acres (1988).

An exhaustive search multiple regression computer program was used to determine relationships between basin characteristics and the curve parameters. The resulting equations were checked for both statistical and physical significance. The best regression equations are given for each of the homogeneous regions in Table 1 along with the multiple correlation coefficient and standard error of the estimate.

The summary statistics relating to the range of dependent and independent variables associated with the regression analyses are given in Table 2 for Regions B, E and F. These ranges of independent variables used in the development of regression equations become the limiting values of the variables which can be safely used in these equations. The equations have all proved to be stable giving reasonable estimates of C, θ and $-\alpha$ for the extreme combinations of variables.

The process of developing the synthetic record at an ungauged site using the regression-based methodology proceeds as follows.

First the daily flow duration curve is derived using the regional regression relationships to estimate the polynomial coefficients C, θ, and α, and subsequently to calculate β, δ and κ, the coefficients of Equation 4. This derived flow duration curve is then adjusted such that

- the probability of exceedance does not exceed one for design discharges at a site with a high degree of natural regulation
- a wavy shape to the flow duration curve is eliminated at low probabilities of exceedance for steep flow duration curve.

Second, a regional index station, selected on a similar basis as the index stations for the proration methodology[1], is used in conjunction with the derived flow duration curve at the ungauged site to synthesize the daily flow record. The calculation proceeds as follows. For each daily discharge of the index time series, the probability of exceedance is determined at the index gauge from the known index flow duration curve, as shown in Figure 3. The discharge at the ungauged site is then estimated from its own derived flow duration curve by assuming the same probability of exceedance as the index station. The discharge record at the ungauged site is created by repeating this process for each flow in the index time series.

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[1] The selected index stations are listed in Table 3.

COMPARISON OF METHODOLOGIES

The two regional methods differ in what they attempt to reproduce. Proration is a direct adjustment of the record at the index gauge by a constant factor, to simulate the historical record. No adjustment is possible for variation such as catchment shape or lake storage, and their effect on the pattern of streamflow.

The regression-based flow duration method simulates the historic record as well, except that the effects of catchment characteristics on the variability of the streamflow pattern are incorporated through the generation of a synthetic flow duration curve.

The overall error resulting from the application of the recommended methodologies was assessed by comparing estimated and actual turbinable flow for various design flows and storages at all gauges used in the analysis.

The actual turbinable flow was computed from daily simulation analyses of the data. The estimated turbinable flow was determined by daily simulation of each synthetic record using both regional techniques.

Representative errors associated with average energy generation were evaluated by examining the case where the installed capacity is based on a flow twice the mean annual flow. At larger installed capacities and at larger storage volumes, errors in estimating turbinable flows are generally damped out. Table 4 contains comparisons of the absolute errors for both methodologies in Regions B, E and F. The errors given include all incurred errors in the methodology such as those attributable to differences between actual and map estimated of MAR.

An inspection of Table 4 indicates that expected regional errors arising from the turbinable flow curve methodology are consistently smaller than those of the proration methodology for any storage condition in terms of

- lower maximum error
- lower average error
- lower standard deviation of error.

When there are no nearby gauges in the same basin with suitable discharge records which could be used to prorate flows at an ungauged site, it is recommended that the turbinable flow methodology be used in Regions B, E and F. Proration to an index gauge should be used in Regions A, C and D where suitable regional regression relationships were not established.

Although not discussed in this paper, techniques for generating synthetic flow records at sites with a short record length gauge in the basin are described by Acres (1988).

COMPUTER MODELS

All of the methods developed as part of the study and described in this paper have been incorporated into separate yet integrated easy-to-use microcomputer programs.

(a) HYSIMONT

Figure 4 shows a conceptual flow chart for the interactive program HYSIMONT which generates daily hydrologic data in the Province of Ontario using either of the two regional methodologies. In addition, this program can also generate synthetic data using a discharge data from a site with a short record.

(b) FLOODONT

Figure 5 shows a conceptual flow chart for the interactive microcomputer programs FLOODONT.

This program was written by Acres (1988) to estimate flood peaks for various return periods using either the index flood method, a composite index flood method or a regional regression approach. This program is based entirely on the studies by Moin and Shaw (1985, 1986).

(c) ENERGY

The program ENERGY is much more complex. This program simulates plant operation where a discharge record is available and summarizes the power and energy capabilities of a site. The program provides maximum flexibility to handle flow regulation through reservoir operation, taking into account plant characteristics, possible downstream limitations on minimum flows, and load variability. The power and energy simulation is calculated using a daily time step. Daily hydrology is recommended to estimate benefits at a small hydro site since small catchments normally exhibit rapidly varying streamflow while reservoir storage is often limited to daily or weekly regulation.

The computer program can generate daily hydrology for a typical period of 30 years in only a few minutes using an IBM-compatible microcomputer.

The simulation program calculates spill flows and accounts for losses in the plant. Energy can be divided into firm and secondary with different monetary values associated with each. Provision has been made for a penalty charge when a preselected firm capacity is not met. With all simulations, some rules for reservoir operation are required. In this program, operation is described by defining, for each month, maximum and minimum reservoir elevations and an elevation below which the plant is operated to meet firm energy needs only.

Each simulation produces overall data on the energy produced and revenue generated, as well as more detailed statistics for each month of the year.

APPLICATIONS

For application of the methodology, a potential user should obtain the study details (Acres, 1988) and the computer programs, together with the associated index gauge flow files on diskette.

The first task is to generate the daily streamflows and for this purpose data is required on the catchment characteristics at the ungauged site and any nearby streamflow gauges. The different methods for generating streamflows have different data needs, which vary from region to region. The data, however, can be extracted from three sources:

1 - National Topographic System - 1:50 000 series mapping of the catchment (1:250 000 mapping is used in some isolated regions of northern Ontario).

2 - Water Survey of Canada - Daily streamflow data

3 - Physiographic Data - (Mean annual runoff, mean annual snowfall and base flow index isoline maps contained in the User's Manual, as well as estimates of centroid latitude/longitude and basin slope).

For energy simulation, the data needs are described in the previous section. Beyond the information noted, additional data on local topography and geology would be required so that a layout and reliable cost evaluation could be developed. A limited amount of information from layout studies is required as input to the energy program developed in this study, including the available head, penstock losses, tailwater rating curves, and reservoir storage curves.

Other information, such as flood return period and minimum flow release requirements, will require consultation with licensing and regulatory agencies.

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Environment Canada
Inland Waters Directorate - Atlantic Region
Executed for Energy, Mines and Resources, 1985

[3] Acres Consulting Services Limited
"Hydrology Design Methodologies for Small-Scale Hydro at Ungauged Sites - Phase 1"
Environment Canada
Inland Waters Directorate
Executed for Energy, Mines and Resources, 1984

[4] Moin, S. M. and Shaw, M. A.
"Regional Flood Frequency Analysis for Ontario Streams, Volume 2, Multiple Regression Method"
Environment Canada
Ontario Ministry of Natural Resources
Canada/Ontario Flood Damage Reduction Program, 1986

[5] Moin, S. M. and Shaw, M. A.
"Regional Flood Frequency Analysis for Ontario Streams, Volume 1, Single Station Analysis and Index Method"
Environment Canada
Ontario Ministry of Natural Resources
Canada/Ontario Flood Damage Reduction Program, 1985

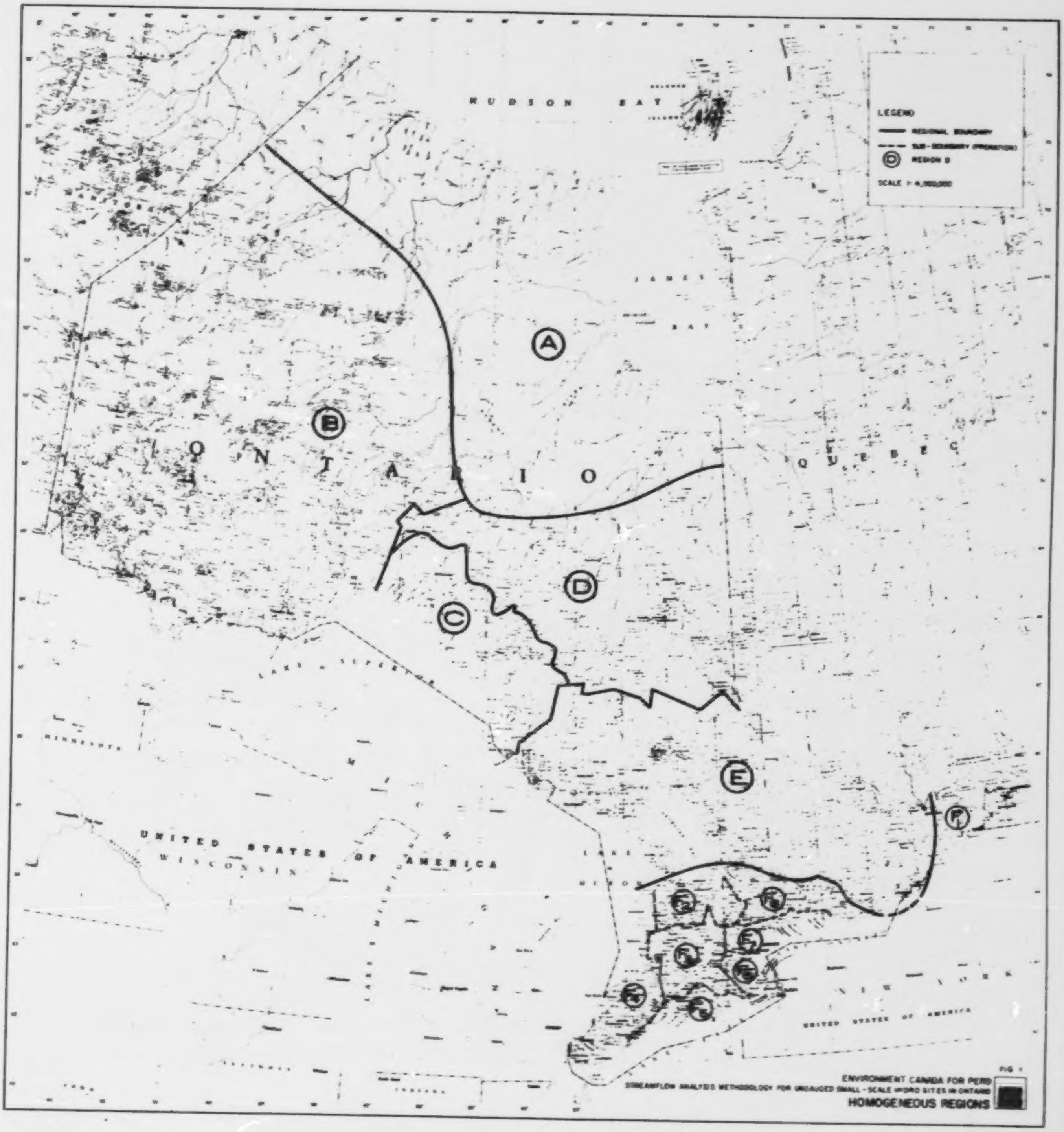

HUDSON BAY
JAMES BAY
ONTARIO
QUEBEC
LAKE SUPERIOR
LAKE HURON
MINNESOTA
WISCONSIN
UNITED STATES OF AMERICA
NEW YORK
A
B
C
D
E
F
LEGEND
REGIONAL BOUNDARY
SUB-BOUNDARY (PROBATION)
D REGION D
SCALE 1: 4,000,000

FIG 1

ENVIRONMENT CANADA FOR PERD

STREAMFLOW ANALYSIS METHODOLOGY FOR UNGAUGED SMALL - SCALE HYDRO SITES IN ONTARIO

HOMOGENEOUS REGIONS

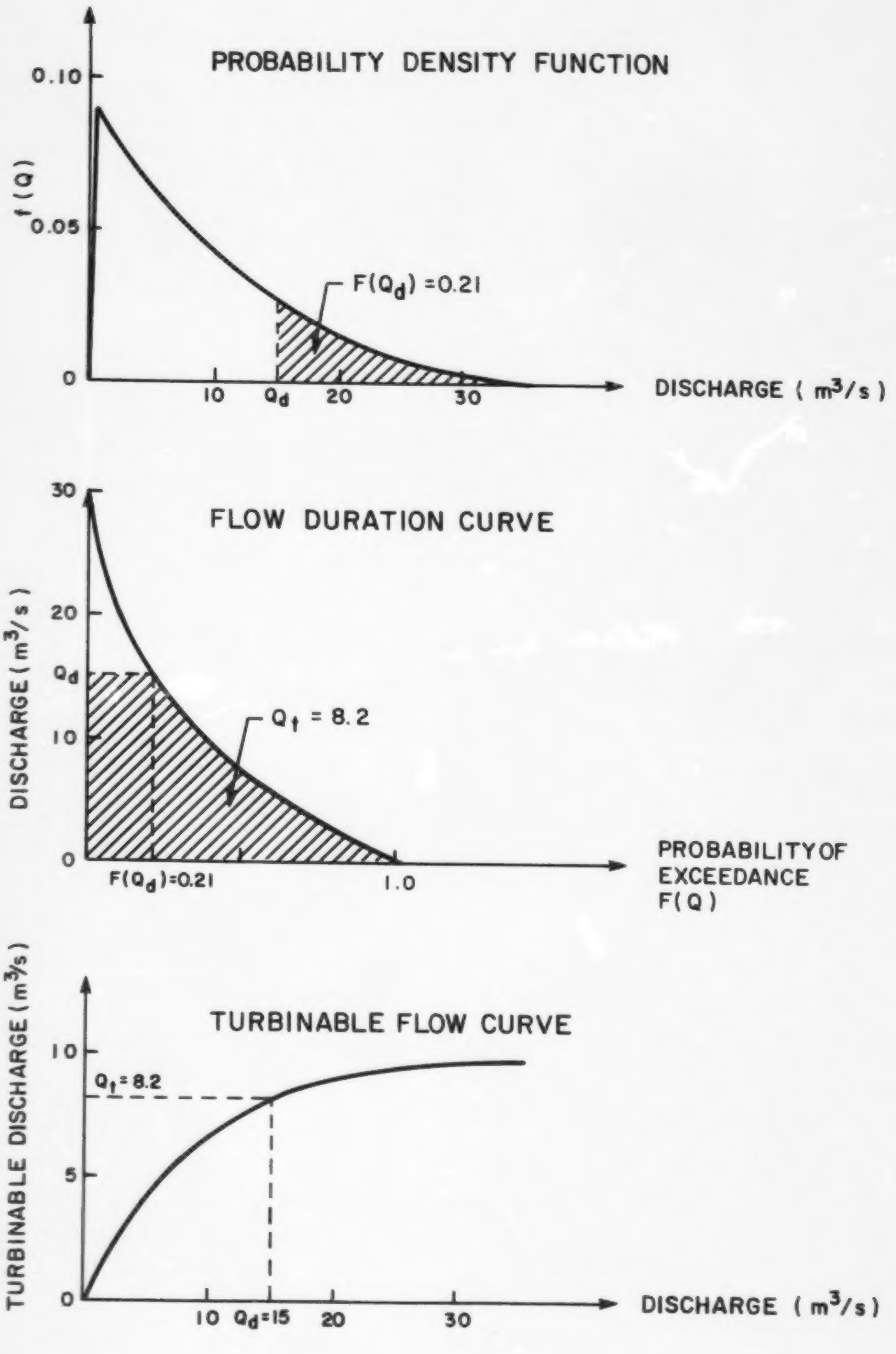
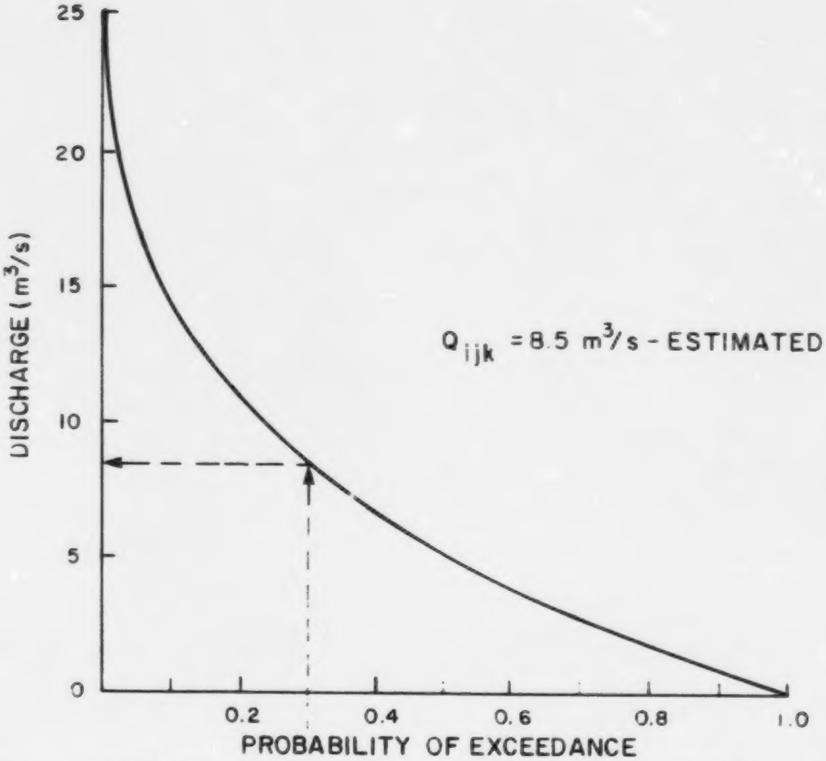


FIG. 2

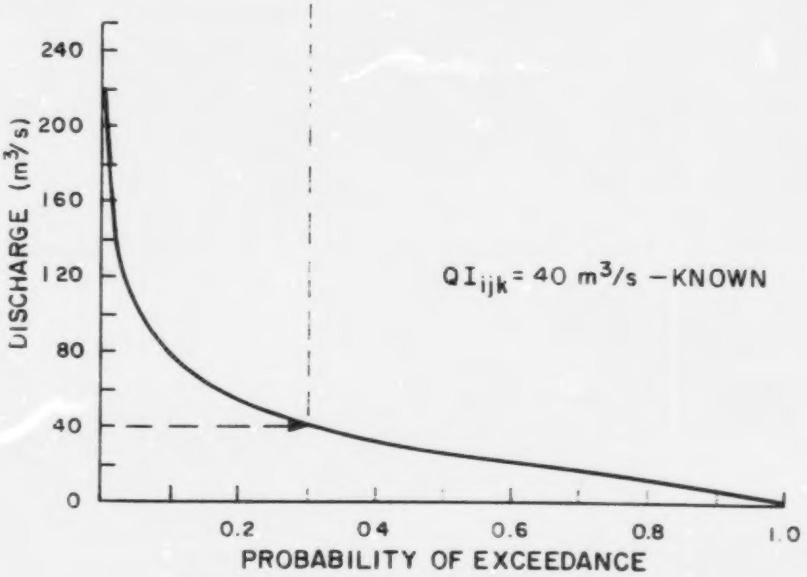
ENVIRONMENT CANADA FOR PERD

STREAMFLOW ANALYSIS METHODOLOGY FOR UNGAUGED SMALL-SCALE HYDRO SITES IN ONTARIO

INTERRELATIONSHIPS OF PROBABILITY DENSITY FUNCTION, FLOW DURATION CURVE AND TURBINABLE FLOW CURVE



ESTIMATED FLOW DURATION CURVE AT UNGAUGED SITE



FLOW DURATION CURVE AT INDEX GAUGE 02YS001

FIG. 3

ENVIRONMENT CANADA FOR PERD

STREAMFLOW ANALYSIS METHODOLOGY FOR UNGAUGED SMALL-SCALE HYDRO SITES IN ONTARIO

DAILY FLOW SYNTHESIS USING FLOW DURATION CURVES

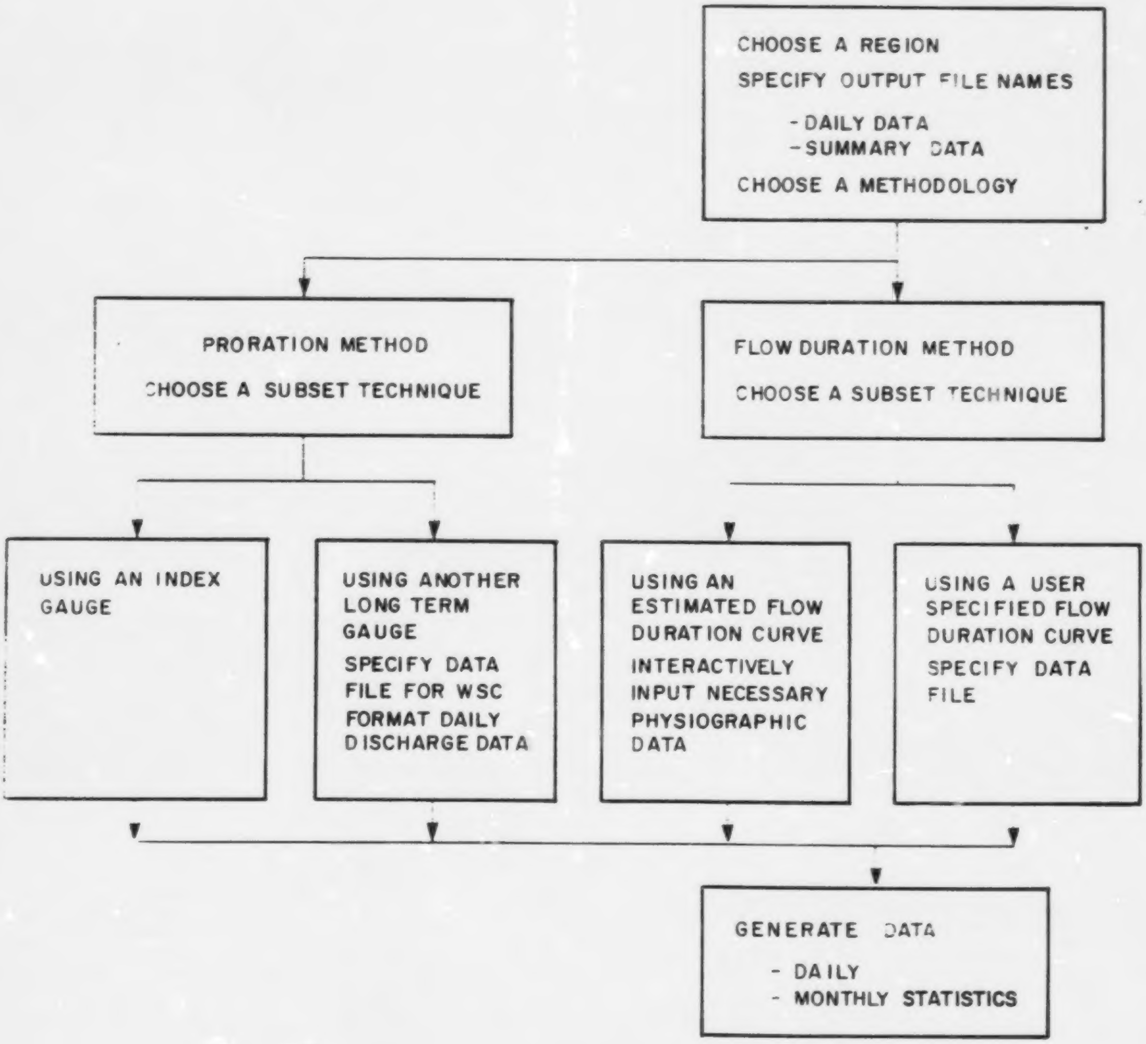

CHOOSE A REGION
SPECIFY OUTPUT FILE NAMES
- DAILY DATA
- SUMMARY DATA
CHOOSE A METHODOLOGY
PRORATION METHOD
CHOOSE A SUBSET TECHNIQUE
FLOW DURATION METHOD
CHOOSE A SUBSET TECHNIQUE
USING AN INDEX GAUGE
USING ANOTHER LONG TERM GAUGE
SPECIFY DATA FILE FOR WSC FORMAT DAILY DISCHARGE DATA
USING AN ESTIMATED FLOW DURATION CURVE
INTERACTIVELY INPUT NECESSARY PHYSIOGRAPHIC DATA
USING A USER SPECIFIED FLOW DURATION CURVE
SPECIFY DATA FILE
GENERATE DATA
- DAILY
- MONTHLY STATISTICS

FIG. 4

ENVIRONMENT CANADA FOR PERD

STREAMFLOW ANALYSIS METHODOLOGY FOR UNGAUGED SMALL-SCALE HYDRO SITES IN ONTARIO

HYSIMONT- GENERAL FLOW CHART

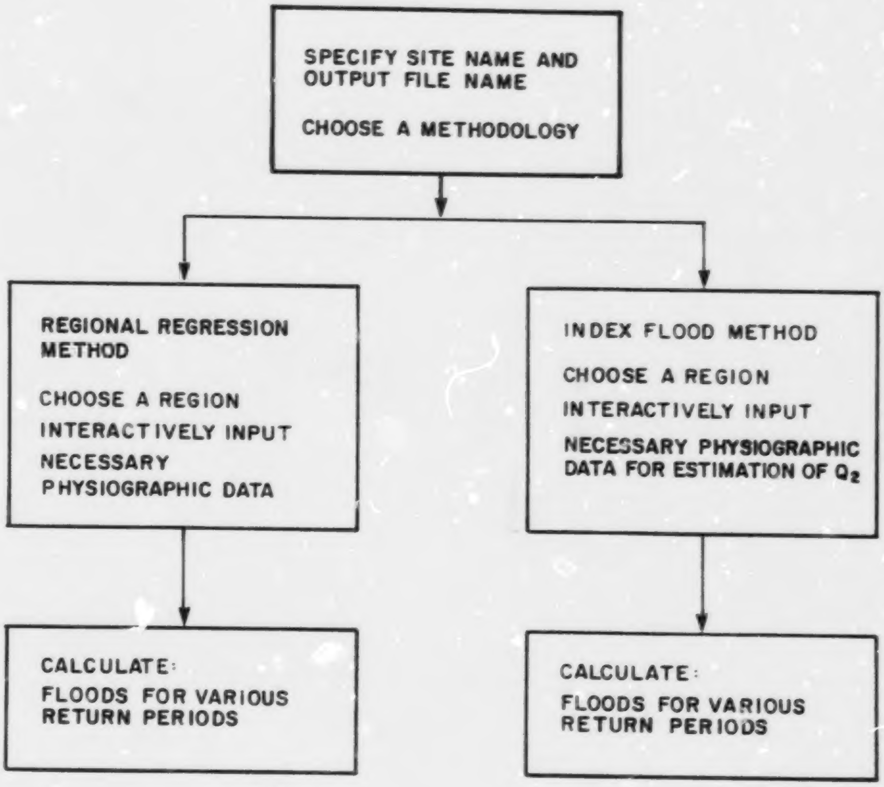

SPECIFY SITE NAME AND OUTPUT FILE NAME
CHOOSE A METHODOLOGY
REGIONAL REGRESSION METHOD
CHOOSE A REGION
INTERACTIVELY INPUT
NECESSARY PHYSIOGRAPHIC DATA
INDEX FLOOD METHOD
CHOOSE A REGION
INTERACTIVELY INPUT
NECESSARY PHYSIOGRAPHIC DATA FOR ESTIMATION OF Q_2
CALCULATE:
FLOODS FOR VARIOUS RETURN PERIODS
CALCULATE:
FLOODS FOR VARIOUS RETURN PERIODS

FIG. 5

ENVIRONMENT CANADA FOR PERD
STREAMFLOW ANALYSIS METHODOLOGY FOR UNGAUGED SMALL-SCALE HYDRO SITES IN ONTARIO

FLOODONT - GENERAL FLOW CHART

TABLE 1

REGIONAL REGRESSION EQUATION SUMMARY

Region	Number of Stations in Region	Equation	Coefficient of Determination (R^2)	Coefficient of Variation (% of mean)	Standard Error of Estimate (% of mean)
B	22	$C = 5$	-	-	-
		$\theta = 0.0707\ MAR^{-0.37040}\ ACLS^{0.12540}\ LAT^{1.08795}$	0.66	11	7
		$\alpha = -\sqrt{0.45970 - 2.04 \times 10^{-6}\ MAR^{2}}$	0.70	12	9
E	15	$C = e^{12.2505 - 0.07497 \ln A - 0.23401 \ln MAR - 1.9535 \ln LONG}$	0.74	12	7
		$\theta = (-2.252 + 0.02583\sqrt{MAS} + 0.09190\sqrt{SLP} + 0.40197\sqrt{LAT})^{2}$	0.91	15	5
		$\alpha = -(-4.618 + 0.02340\sqrt{MAS} + 0.0718\sqrt{SLP} + 0.72005\sqrt{LAT})^{2}$	0.91	23	8
F	62	$C = 9.533 - 6.137\ BFI$	0.88	14	5
		$\theta = 0.3057 + 1.1641\ BFI + 0.036\ SLP$	0.89	22	8
		$\alpha = -0.0851 - 0.7346\ BFI - 0.0273\ SLP$	0.80	28	13

TABLE 2

SUMMARY OF INDEPENDENT AND DEPENDENT REGRESSION VARIABLES

Region	Description	Independent Variables											Dependent Variables		
		Drainage Area (km^2)	Mean Annual Precip. (mm)	Mean Annual Snowfall (cm)	Mean Annual Runoff (mm)	Base Flow Index	Area Controlled by Lakes and Swamps (%)	River Slope (m/km)	River Length (km)	Latitude (degrees)	Longitude (degrees)	Shape Factor	C		
B	Minimum	619	540	190	**195**		**20.00**	0.018	59.1	**48.88**	86.53	2.2	5.00	0.88	0.388
	Maximum	24 200	770	300	**389**		**100.00**	0.838	358.8	**54.99**	94.46	26.8	5.00	1.27	0.618
	Mean	7 603	675	229	**291**		**80.00**	0.281	192.0	**51.83**	90.47	7.1	5.00	1.10	0.530
		6 427	72	28	**56**		**29.00**	0.231	84.0	**1.85**	2.14	5.8	0.00	0.10	0.060
	CV (%)	85	11	12	**19**		**36**	82	44	**4**	2	82	0	9	12
	Extreme Min												5.00	0.76	0.388
	Extreme Max												5.00	1.39	0.618
E	Minimum	**149**	795	**170**	**344**		0.01	**0.138**	24.5	**44.21**	**75.66**	1.4	5.40	0.71	0.324
	Maximum	**1 850**	930	**300**	**626**		98.00	**2.472**	128.0	**46.57**	**81.25**	14.2	7.30	1.08	0.576
	Mean	**709**	864	**228**	**425**		49.00	**1.290**	66.1	**45.24**	**78.35**	7.4	6.40	0.89	0.430
		485	44	**49**	**82**		36.00	**0.656**	30.0	**0.73**	**1.91**	3.7	0.60	0.12	0.090
	CV (%)	**68**	5	**21**	**19**		73	**51**	45	**2**	**2**	49	9	14	22
	Extreme Min												4.90	0.63	0.251
	Extreme Max												7.80	1.17	0.662
F	Minimum	163	780	100	225	**0.15**	0.01	**0.208**	20.0	42.46	74.64	1.5	4.60	0.50	0.213
	Maximum	5 206	1000	300	516	**0.81**	100.00	**4.824**	227.5	48.31	82.34	21.8	8.60	1.32	0.738
	Mean	841	882	203	376	**0.45**	19.00	**1.482**	59.9	43.69	80.44	5.8	6.80	0.88	0.460
		1 066	61	59	62	**0.14**	31.00	**0.896**	42.2	0.89	1.49	3.7	0.88	0.18	0.120
	CV (%)	127	7	29	17	**32**	170	**60**	70	2	2	63	13	21	26
	Extreme Min												4.60	0.49	0.200
	Extreme Max												8.60	1.42	0.810

Note: Variables shown in bold were significant in the regression equations.

TABLE 3

INDEX GAUGE SUMMARY FOR FLOW DURATION CURVE METHODOLOGY

Region	Station	Period of Record	Length of Record (years)	Type	Drainage Area (km^2)	Record Quality
B	04DA001	1967-1986	20	natural	5960	average
E	02HL004	1959-1986	28	natural	671	above average
F	02GG002	1949-1986	38	natural	730	above average

INDEX GAUGE SUMMARY FOR PRORATION METHODOLOGY

Region	Station	Period of Record	Length of Record (years)	Type	Drainage Area (km^2)	Record Quality
A	04DC002	1972-1986	15	natural	4 710	average
	04FC001[1]	1968-1986	19	natural	36 000	average
B	04DA001	1967-1986	20	natural	5 960	average
C	02BA002	1970-1986	17	natural	1 190	above average
D	04LJ001	1921-1986	66	natural	8 940	above average
E	02HL004	1959-1986	28	natural	671	above average
F1	02MC001	1961-1986	26	natural	358	average
F2	02ED003	1950-1986	37	natural	1 180	average
F3	02FE008	1968-1986	19	natural	648	above average

---

[1] Assumed to be representative of all stations having drainage area greater than 25 000 km^2.

Table 3 (contd)

Region	Station	Period of Record	Length of Record (years)	Type	Drainage Area (km^2)	Record Quality
F4	02GG002	1949-1986	38	natural	730	above average
F5	02GC010	1961-1986	26	R2	342	average
F6	02HA006	1958-1986	29	natural	293	average
F7	02HC025	1963-1986	24	natural	303	average
F8	02EC011	1967-1986	20	natural	282	average

TABLE 4

AVERAGE ABSOLUTE ERROR OF METHODOLOGIES

(expressed as a percent)

Region	Methodology	Description	Storage (Ratio to Mean Flow Volume) 0	0.05	0.1	0.2	Average
B	Proration	Average	7.5	5.3	4.3	3.2	5.1
		Maximum	23.3	17.7	15.8	13.7	17.6
		σ	6.9	4.8	4.0	3.4	4.6
	Flow Duration	Average	4.4	3.3	3.0	2.7	3.4
		Maximum	14.2	12.5	12.0	12.7	12.7
		σ	3.6	3.3	3.2	3.5	3.2
E	Proration	Average	8.8	7.7	6.9	4.8	7.0
		Maximum	20.9	16.1	14.4	11.1	15.5
		σ	6.2	4.8	4.3	3.4	4.6
	Flow Duration	Average	5.3	4.2	3.6	2.8	4.0
		Maximum	13.7	8.4	7.3	5.9	8.5
		σ	4.2	2.6	2.3	1.7	2.6
F	Proration	Average	13.9	10.1	8.1	5.6	9.4
		Maximum	83.5	45.9	33.0	20.2	45.7
		σ	12.7	7.7	5.9	4.1	7.3
	Flow Duration	Average	7.7	6.3	5.4	3.3	5.7
		Maximum	30.8	27.5	24.9	17.3	24.7
		σ	6.8	5.2	4.6	3.7	4.6

Small Hydro in Remote Canada and Developing Countries

By
F.H. Schwartz

25

PRESENTATION

TO

SMALL HYDRO '88

SMALL HYDRO IN REMOTE CANADA AND DEVELOPING NATIONS

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SMALL HYDRO IN REMOTE CANADA AND DEVELOPING NATIONS

1. Introduction

This presentation is focussed on the off-grid development of small hydro sites. It draws on experience mainly in remote Canada and relates this to conditions found in developing countries.

These off-grid or remote installations are generally harder to accomplish than grid connected sites, and are generally more rewarding to the developer because of higher rates obtained for the power.

With on-grid rates for power ranging from about three (3) to five (5) cents (per kilowatt-hour) for the power, remote rates at seven (7) to thirty (30) cents for the power make these sites extremely attractive to develop. This added premium for the power is needed and welcome, because remote installations are costlier to implement, due to complicated transportation and logistics, and a general lack of skilled manpower, materials, and equipment availability in proximity to the sites.

2. Development Concepts and Engineering

Because of the difficulties of access to sites, and higher costs, there is room for the use of innovative development concepts and a careful choice of technology to match the specific needs on site. There is even room for the development and application of innovative technology such as the containerized system developed by Dave de Montmorency for use at remote sites.

2. Development Concepts and Engineering - (Cont'd.)

Remote sites benefit from the use of what I call the "small power engineering approach". This approach uses the revenues generated on site to determine the developmental scheme for the site. This way, costs are kept within the bounds of what the revenue stream can bear, whereas, with the "utility approach" development costs are not linked to the revenue produced at that site. Thus, the concept only allows for development costs that the cash flow can support.

3. Potential Across Canada

The potential for remote sites in Canada is quite large, with over 370 remote communities being strung out over a territory with a lot of water flowing across it. In many areas, such as the James Bay and Hudson Bay lowlands, there is not a lot of potential. However, in other areas such as Quebec, Newfoundland and Labrador, British Columbia and in Northwestern Ontario there are good sites. Estimates of potential are:

British Columbia	30 megawatts
Quebec	10 megawatts
Newfoundland/Labrador	5 megawatts
Ontario	5 megawatts
Alberta	5 megawatts
Northwest Territories	2 megawatts
	57 megawatts

3. Potential Across Canada - (Cont'd.)

These estimates are only approximate, and with further study, may be higher, and in some cases, may be lower. Figures for the Northwest Territories are not verified, due to the surprising lack of information on small hydro potential in the Northwest Territories.

4. Potential in Developing Countries

The Canadian potential is miniscule when taken in comparison to the potential in developing countries. Canadian developers have had a share of the small hydro development in the developing countries, with installations in Gabon, Swaziland, Sri Lanka, Sierra Leone, Jamaica, The Dominion Republic, Honduras, Brazil and Peru. Overall, potential is tremendous in Pakistan, India, the Philippines and Indonesia.

5. Development Rules and Regulations

The rules and regulations for development in remote Canada and developing countries are quite different. In Canada, the developer is dealing with a well defined area and set of agencies to deal with. The developer is referred to the manual produced by the writer for Energy Mines and Resources Canada on relations between Small power producers and utilities in remote Canada, which provides details of government approvals and utility policies across Canada. This manual will be available through EM&R head office and through the local Conservation and Renewable Energy Offices in the regions, and is entitled Small Power Production for Remote Communities - a Shared Opportunity.

5. Development Rules and Regulations - (Cont'd.)

- One major point which needs to be made is the extreme sensitivity that must be used with local people in the development process.
- In Canada this relates largely to native people, their needs, rights, and the land-claims process.
- The developer is best to investigate local political and environmental sensitivities, like issues related to local fishing and forestry resources, issues of grid connection, the use of local labour and construction companies, the status of local land claims, etc.
- Elsewhere, the developer is best to investigate local business habits, government regulations, and ways of doing business. This cannot be stressed enough given the reputation that western businessmen have for ignoring or being insensitive to local interests in developing countries.

6. Unique Challenges with Remote Installations, Transportation and Logistics

Transportation and logistics can cause extreme problems in relation to remote installations. Frequently, access to sites are severely limited, and may only be provided by air, or water. Further, as in the case of the Mary's Harbour installation in Labrador, transportation may only be provided by a single carrier, in this case CN Marine who have specific schedules and lots of other customers. Care should be taken when formulating a project to carefully factor in transportation and scheduling to and from the site.

7. Slide Presentation

I will now show slides to illustrate some of the difficulties encountered in remote installations, and some of the innovative materials and designs developed to deal with the problems.

Location, Capacity, Cost	Particular Features Described
Laurentian Lodge, Ontario 30 kw, $100,000	o Containerized watertite small kaplan turbine which sits in headpond. Good up to 50 feet of head.
	o Long draft-tube down to tailrace.
	o Replacement of diesel generation.
Millcroft Inn, Ontario 20 kw, $ 80,000	o Containerized unit in headpond to avoid icing problems. Ice builds up over container; if system goes down, water is evaculated from whole system by gravity.
	o Does not rely on valves which may become frozen/inoperable.
	o Only two components to system-avoids using penstock and powerhouse.
Frontier Lodge, Ontario 80 kw, $200,000	o Unique use of PVC penstock tied down to railroad ties.
	o Use of small kaplan turbine and minimal equipment on site to install.
	o Replacement of diesel generating and increase of power availability.

7. **Slide Presentation - (Cont'd.)**

Location, Capacity, Cost	Particular Features Described
Frontier Lodge, Ontario 80 kw, $200,000 cont'd.	o Sequence of slides from manufacture of turbine, to off loading of equipment, assembly, installation in powerhouse, coupling of penstock, and roofing of powerhouse.
Mary's Harbour, Labrador 150 kw, $650,000	o Private sector project which required widespread cooperation amongst various government agencies and regulatory bodies, and rewriting of some legislation regarding small hydro installations.
	o Intitial problems encountered with ice in intake canal, electrical components. Problems now solved.
	o Problems encountered with transportation and logistics.
	o Project was first one authorized by Newfoundland and Labrador Hydro, so required development of power purchase policy by utility.
Wasdell Falls, Ontario 135 kw	o Mini Hydel prototype by Barber Hydraulic turbines for Ontario Hydro. Intended for use at remote sites.

7. Slide Presentation - (Cont'd.)

Location, Capacity, Cost	Particular Features Described
Sandy Lake, Ontario 1.5 mw	o Old plant no longer in use. Used to serve a gold mine. o Site currently held by Zehavey Mines. Could be redeveloped to serve mine site or community of Sandy Lake.

Rural Electrification and Rural Development in Algeria: Policies and Performances

By
A. Djeflat

2

ONTARIO MINISTRY OF ENERGY

SMALL HYDRO '88

International Conference and Trade Show

4 - 9 JULY 1988

RURAL ELECTRIFICATION AND RURAL DEVELOPMENT IN ALGERIA : POLICIES AND PERFORMANCES

---

by

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May 1988

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Presenting it to the International Conference Small Hydro'88 is one way to contribute to the dissemination of its results , on top of the publication made by the International Labour Office . May we express our thanks to the organisers of the conference for giving us this opportunity .

CHAPTER 1

INTRODUCTION

Energy is an essential key to the work of people anywhere. In rural areas of developing countries human and animal power are still predominant energy sources but the process of rural development more or less implies that people gradually shift to using more efficient, commercial sources of energy, in particular electricity.

Almost all developing countries devote a major share of their public investments to expanding the power sector, relying heavily on imports of plant and equipment.[1] Most of these investments concern an expansion of generating capacity and high voltage transmission. In recent years however, ever larger sums are being allocated to ensure the widespread distribution of electricity. Rural electrification, that is extending the grid to rural villages, has thus become an important enterprise in many developing countries.

Both political and socio-economic objectives may be pursued through rural electrification; the dividing line between the two categories is not always clear. In any case, it appears that rural electrification and thereafter the consumption of electricity in rural areas, often depend on government subsidies. Such public funds are typically released on the assumption that access to electricity yields all sorts of benefits which are bound to exceed costs, maybe not immediately but certainly over the years. Assumptions about the benefits of rural electrification are often made however, without a clear picture of rural energy demand or the factors which influence the use of electricity. Little tends to be known about the extent to which electricity substitutes for other energy sources, commercial or non-commercial. Opportunities which are believed to exist for the productive use of electricity are not usually verified before a decision to extend the grid is taken. In fact project appraisal is mostly concerned it seems, with project costs and technical detail such as the sort of poles to be used, the number of transformers, measures to reduce power losses, or maintenance procedures.

This paper is about the socio-economic impact or rural electrification in Algeria. It does not present an ex-post cost-benefit analysis of past investments, as data for such an exercise are largely lacking; moreover considerable effort would be required to resolve certain methodological issues. The paper reports on a survey of households and establishments we undertook in a sample of villages to find out about the circumstances in which electricity is used or not, about levels of consumption and expenditure on electricity and alternative energy sources, and about benefits of electrification as consumers perceive them.

Few people would be surprised to learn that households appreciate access to electricity as a tangible proof of modernisation and that they attribute gradual improvements in the quality of rural life to key factors such as being able to watch television. We wanted to know more precisely however, how the use of electricity benefitted rural people.

Our aims had to be met with limited resources and was not easier for the fact that this was the first study of its kind for Algeria. A recent report on rural electrification by SONELGAZ, the State monopoly for the generation, transmission and distribution of electricity, contains some useful data but is broad and prospective in nature; it is essentially a pluriannual programme of work.[2]

Rural electrification is an important issue in Algeria as it is explicitly mentioned in the country's National Charter of 1976. It is worth noting that this basic policy document only refers to introducing electricity to all of the country's households by the end of the 1980s; there is no reference to the productive use which could be made of electricity on farms and in rural industries. This may be a reflection of the fact that economic activities in Algeria are largely urban-based.

Algeria had a population of some 20 million in 1982 with a per capita GNP of US$2350. Unlike many other developing countries, its' economy is far from dominated by agriculture. As a result of slow growth of the agricultural sector, a deliberate policy of industrialisation and in particular, the rapid rise to prominence of the hydrocarbons sector, the share of agriculture in GDP dropped from 15 per cent in 1962 to 6 per cent in 1982; industry accounted for 55 per cent in 1982, of which 10 per cent was manufacturing, and services for 39 per cent. Although 55 per cent of the country's population lived in rural areas in 1982, only 25 per cent of the country's labour force was in agriculture as compared to well over 60 per cent at the time of independence.[3]

Only 7.5 million ha, or 3 per cent of Algeria's total land area is considered cultivable; in 1979, 44 per cent of cultivable land was fallow, 39 per cent under winter cereals (wheat, barley, rye) and the rest mainly used for growing fruit, vegetables, pulses and forage. Agricultural production is concentrated in the north of the country, where most of the people live and where soil and climatic conditions are most suitable. Most of the production is dependent on rainfall rather than irrigation, which explains considerable annual variations in output.

Governments' current policy in respect of agriculture stresses self-sufficiency in food; diversification of crop production, improvement of rural employment and incomes, and of rural infrastructure, improvement of the marketing of agricultural products and the supply of inputs, and a relative improvement in the situation of the rural poor. The share of agriculture in the country's public investments is estimated at six per cent in the 1980-84 plan period.

In the early 1970s the Algerian Government launched a major rural development scheme with the aim of constructing throughout the country 1,000 "socialist villages" fully equipped with up-to-date conveniences such as electricity. In drawing our sample we introduced a bias by including 14 "socialist" as against 22 "traditional" villages; it was hoped that this would allow us to assess to what extent the impact of electrification would vary with inputs of a complementary nature. More details on the methodology we adopted are included as an annex to this report.

Following this introductory chapter, there are short chapters on the generation and consumption of electricity in Algeria and more specifically on the nature and scope of the rural electrification effort. In Chapters 4 and 5 the results of our survey are presented for households and establishments respectively. Chapter 6 contains a summary of conclusions and some concluding remarks.

CHAPTER 2

GENERATION AND CONSUMPTION OF ELECTRICITY IN ALGERIA

Electricity was first supplied in Algeria during the French colonial occupation of the country and electrification was closely linked to the economic policies of the colonisers. In 1947, the French Government nationalised the electricity sector and created a public utility corporation for the generation and distribution of electricity and gaz, Electricité et Gaz d'Algérie (EGA).

The production of electricty, in particular to supply urban centres in the North of the country and villages with French colonial communities and farms, increased at a steady rate of around 7 per cent per year from 417 million kWh in 1947 to 1380 million kWh in 1961, the eve of independence.

After independence in 1962, the electrification of centres until then without supply from the grid became an increasingly important concern of the Algerian Government. Initially progress was modest for various reasons, in particular a lack of construction capacity, organisational problems related to shortages of qualified personnel, and difficulties in the supply of electrical equipment. The EGA was mainly concerned with the maintenance of existing plant and equipment.

With the creation in 1969 of the Société Nationale d'Electricité et du Gaz (SONELGAZ) to replace the EGA, and the implementation of the country's first four-year development plan (1970-1973), electrification advanced rapidly. As a result, the number of centres electrified went up from 73 in the 1965-1970 period to 727 in the 1970-1975 period and the number of new connections from about 15,000 to 133,000. From 1965 to 1975 some 500 million DA were spent on electrification, 10 million DA in 1966, 40 million DA in 1970, and 120 million DA in 1975.[4] A census of non-electrified centres which SONELGAZ conducted in 1974/75 showed nonetheless that a great deal remained to be done in order to achieve total electrification.

The National Charter adopted by referendum in 1976 constitutes Algeria's main source of current policy and legislation. It stipulates inter alia, that the whole country should be electrified so that all households will have been connected by the end of the 1980s. A comprehensive Plan National d'Electrification (PNE) was therefore approved by the Council of Ministers in March 1978. The Plan is aimed at bringing the rate of electrified households to 96 per cent by 1987 at a total cost (in 1976 prices) of almost 5,000 million DA (roughly 1,000 million US dollars). The PNE envisages the electrification of 12,100 centres with an estimated 1,200,000 household connections which would require some 58,000 km of medium and low tension lines and 11,700 transformer stations. The implementation of the Plan would create 4,500 new jobs. The PNE is essentially concerned with distribution, that is with extending the grid to each and every village; it is therefore a rural electrification programme. We will come back to details in Chapter 3.

The current emphasis on distribution follows earlier major efforts towards augmenting the country's generating plant. In particular during the 1970s large investments in electricity generation were necessary to meet the increasing demand from the industrial sector which assumed priority in Algeria's first and second four-year development plans. In the five-year development plan 1980-1984, no additional generating capacity is proposed. Instead, almost 1,500 million DA (some 3,000 US$) are to be invested for completing generating projects carried over from earlier plan periods (such as the Marsat-el-Hadjadj and Tamanrasset plants), for the necessary replacement of existing plant and, in accordance with the PNE, for transmission and distribution. It is perhaps worth noting that in general the emphasis in the 1980-1984 five-year plan is less on industrialisation than in earlier plans and much more on strengthening agriculture and social services.

Table 2.1. shows the growth of net installed capacity of electric generating plants between 1950 and 1980. As regards choice of technology it may be noted that the share of hydro-electric plants in total capacity dropped from 42 per cent in 1960 to 14 per cent in 1980. In terms of consumption the share of hydro-power dropped from 26 to 4 per cent over the same period (Table 2.2).

Before the discovery and exploitation of oil and gas in 1956, hydro-power was estimated to be cheaper than electricity produced in thermal plants using coal. However, the hydro plants depended a great deal on rainfall which meant

Table 2.1.

Algeria: Net installed capacity of electric generating plants by type ('000kW)

Year	Thermal	Hydro	Total
1950	237 (72%)	92 (28%)	329
1960	253 (58%)	186 (42%)	439
1970	464 (62%)	286 (38%)	750
1980	1720 (86%)	286 (14%)	2006

Source: United Nations, 1982 Yearbook of World Energy Statistics, New York, 1984.

Table 2.2.

Algeria: Consumption of electricity (total in GWh='000 kWh; per capita in kWh)

Year	Thermal	Hydro	Total	Per capita
1950	456 (78%)	131 (22%)	587	67
1960	977 (74%)	348 (26%)	1325	123
1970	1399 (71%)	580 (29%)	1979	144
1980	6872 (96%)	251 (4%)	7123	382

Source: United Nations, 1982 Yearbook of World Energy Statistics, New York, 1984.

that electricity production was irregular. By 1962 most thermal plants had stopped using coal in favour of oil and gas. From 1970 onwards gas-powered turbines were chosen systematically and existing plants burning oil were converted to gas of which important reserves had been shown to exist.

In Table 2.2, consumption is defined as production plus imports minus exports of electricity. As until recently there was hardly any trade in electricity between Algeria and Tunisia, whose grids are inter-connected, there appears to be no difference between production and consumption figures, which implies that power losses are considered as consumption. SONELGAZ reports that it distributed 5,393 GWh or 76 per cent of Algeria's electricity consumption in 1980; another 13 per cent was consumed by auto producers - a small number of large industrial companies; the remainder was consumed in the form of transport - and distribution losses.

SONELGAZ counted 43 high tension and 7,714 medium-tension consumers in 1980, most of them industrial companies; the two categories accounted for 35 and 38 per cent respectively of total SONELGAZ distribution. The rest, 26 per cent, was sold to 1,435,851 low-tension consumers, mainly households; this amounts to just under 1,000 kWh per connection per year. Most households by far are served by the Northern grid; only 7 per cent are connected to the Southern grid.

It may finally be noted that Algeria's per capita electricity consumption almost trebled during the 1970s. At almost 400 kWh per capita in the early 1980s the country compared with e.g. Egypt (410 kWh), Syria (428 kWh), Tunisia (438 kWh) and the Islamic Republic of Iran (442 kWh).[5]

CHAPTER 3

RURAL ELECTRIFICATION IN ALGERIA

Electrification authorities acknowledge that the line between urban and rural areas is loosely drawn. The National Electrification Plan (PNE) avoids the issue by referring to centres yet to be electrified. Many consider a centre to be the area, town or village, run by an Assemblée Populaire Communale (APC) or local council. If population size is taken as a yardstick, almost all of the centres to be electrified have less than 5,000 inhabitants and less than 1,000 workers in the non-agricultural sector - figures which have been used by others to define a rural village.[6]

The Algerian Government considers rural electrification as an important instrument for the implementation of its rural development policy. Rural electrification is seen as a means to achieve political and socio-economic objectives and indeed as a solution to some of the urgent problems which rural people face.

From a political point of view, the rural people had contributed a great deal to the liberation struggle (1954-1962) and deserved therefore to be rewarded in terms of better living conditions after independence. Moreover, rural electrification is seen as a means to promote greater equity between urban and rural areas, an aim which is inherent in Algeria's socialist approach to development. As is stated in the preamble of the first four-year development plan (1970-1973): "The Algerian Revolution should provide all towns and villages the facilities which families in the modern world need most for their everyday lives: water, electricity and gas".[7]

Rural electrification is also expected to contribute to reducing rural-urban migration which is a serious problem in Algeria. However, it is not considered as a sufficient condition to stem such migration. Various schemes have therefore been introduced simultaneously, notably the establishment of 1,000 "socialist villages".

In some developing countries and notably in India, rural electrification is in the first place meant to contribute to the development of irrigation.

The situation in Algeria is different. The total irrigated area was estimated to be 462,000 ha in 1980, or 6 per cent of the country's cultivable land. Some 40 per cent of the irrigated area was served by flood water spreading, and 60 per cent was under controlled irrigation. As in the latter case, surface rather than ground water is being used, most of the water is moved by gravity instead of other forms of energy. Where water is being pumped, diesel sets tend to be used.

The current 1980-1984 plan envisages considerable investments in irrigation in the first place in order to stem the deterioration of existing surface-water irrigation schemes and furthermore in order to expand these large schemes and create some new ones so as to irrigate an extra 50,000 ha by 1985. Small and medium scale irrigation will also be promoted, notably but not exclusively, to exploit ground water. The small and medium scale projects would together add another 40-50,000 ha to the country's irrigated area by the end of the plan period. We have found no explicit reference however to suggest that electricity should be the favourite energy source for pumping ground water.[8]

It is indeed worth noting from various statements and implicit policies that rural electrification is seen more as an instrument for improving the rural way of life than as a means to boost the rural economy. Rural electrification is considered as one of the social amenities which the State should provide for, not unlike housing, drinking water, education and roads.

Although rural electrification got underway in the ealy 1970s, it was not until the adoption of the National Electrification Plan (PNE) in 1978 that it was done in a systematic manner. It was decided that within certain cost limits the grid would be extended to clusters composed of a variety of small and large centres, thus leaving certain scattered consumers out ("electrification en grappe"). Although one opted for a centralised system of generation, transmission and distribution, the possibility of decentralised systems in special circumstances was not excluded. Thus it appears, for example, that local research on solar energy is making good progress and that solar technology is likely to be adopted as the most appropriate for villages in remote areas, in particular in the Saharian south.

SONELGAZ is responsible for the implementation of the plans and policies in respect of rural electrification adopted at the level of Government. In practice however, the company is heavily involved in decision making in view of its technical expertise and the information at its disposal.

A few years ago SONELGAZ established a subsidiary to deal with the actual implementation of rural electrification projects. This enterprise, called KAHRIF[9] operates with a staff of 4,500 mainly through six departments located in as many regions of the country. Each regional department enjoys a certain autonomy as regards the implementation of its part of the PNE. KAHRIF is thus involved in project appraisal, discussions with local authorities, and the subsequent construction activities. As KAHRIFs own capabilities proved not always adequate, a series of small local construction companies were created throughout the country; to date, some 23 of these public sector companies (Société de Willaya) exist.[10] In addition private construction companies are called on to assist as and when necessary.

Investments in the power sector rely on various sources of finance including the State budget, SONELGAZ revenues, and in particular medium- and long-term loans from national financial institutions such as the Banque Nationale d'Algérie and the Banque Algérienne de Développement; external loans from public institutions such as the African Development Bank or the World Bank or from commercial banks, are used to finance imports of equipment and services and therefore expenses in foreign currencies.

Rural electrification, which remains a relatively minor part of total investments in the power sector, is more or less considered as a public service, and therefore mainly funded by the State in the form of grants to SONELGAZ. Details on the precise cost of rural electrification could not be obtained in the context of the present study. The PNE however envisaged a total expenditure of almost 5,000 million DA (1976) in order to meet its targets.

Table 3.1.

Annual expenditure 1978-1987,

Plan National D'Electrification, millions of DA (1976)

Year	78	79	80	81	82	83	84	85	86	87	ULT	TOTAL
Expenditure	235	300	400	500	500	500	500	500	500	500	500	4935

Source: PNE, p. 19.

Table 3.2.

Material requirements for the implementation of the National Electrification Plan, 1978-1987

Type of material	Quantities
Steel poles	257,000 units
Concrete poles	614,400 units
Wooden poles	89,500 units
Total poles	960,900 units
Aluminium cables /wires	145,460 tonnes
Copper cables/wires	1,300 tonnes
Total cables/wires	146,760 tonnes
Switchgear and meters	940,000 units
Transformers and conductors	11,430 units
Insulators	5,625,000 units

Source: Calculated from PNE, p. 32.

To get an idea of the PNE's scope, table 3.2 with data on material requirements is included. It is not easy to determine the import content of the package. In any event, in addition to some private firms producing limited quantities there are three major state enterprises manufacturing some of the electrical equipment and materials required. Steel poles are produced in sufficient numbers by SN Metal after the start of nine new production units in various parts of the country. ONAMHYD produces around 70,000 concrete poles per year which would seem to be sufficient for current levels of demand. SONELEC produces cables, wires and conductors but in insufficient quantities. In 1982, 78 per cent of local demand had to be imported from abroad.[11] Local production of transformers, switchgears and meters has started gradually in 1980. Insulators and other accessories, as well as wooden poles are mostly imported for lack of local production.

As mentioned earlier and borne out in Table 3.3, rural electrification took off in the 1970s, in particular with the country's second four-year development plan (1974-1977). The annual average number of new connections jumped from 19,053 during the 1970-1973 period to 68,696 during 1974-1977. During the current five-year plan period new connections are estimated at 114,000 per year.

Table 3.3

Rural electrificaion: newly connected centres and consumers, 1970-1984

Period	New Centres	Annual Average	New Consumers	Annual Average
First Four-Year Plan (1970-1973)	436	109	76,213	19,053
Second Four-Year Plan (1974-1977)	1,438	360	274,782	68,696
1978 and 1979	675	338	91,729	45,865
Five-Year Plan* (1980-1984)	3,665	733	570,000	114,000

Source: SONELGAZ statistics.

* estimated.

It is estimated that at the beginning of the current five-year plan in 1980, some 10,000 centres or about 900,000 households remained to be connected. This means that if plan targets were met, some 6,500 centres with some 330,000 households would still be without connection by early 1985. It may be noted that the number of households per centre decreases rapidly which indicates that ever smaller villages are connected to the grid.

A progress report before the Council of Ministers in May 1984 suggested that 95 per cent of the targets were met in 1983, against 65 per cent in 1979.[12] It thus appears that problems which gave rise to delays and cost overruns in the 1970s have been tackled with some success. These problems included notably a lack of experienced manpower, slow work by subcontractors, bottlenecks in the supply of materials and equipment, and cumbersome administrative and financial procedures.[13]

The national electrification rate had reached 75 per cent in 1983 up from 61 per cent at the beginning of the current plan. Out of 31 willayates (districts), 15 had an electrification rate above the national average of which 10, no doubt the most populated, were electrified for more than 90 per cent. Only one willaya had a rate under 50 per cent (47 per cent) by the end of 1983.[14]

CHAPTER 4

SOCIO-ECONOMIC IMPACT OF RURAL ELECTRIFICATION ON HOUSEHOLDS

4.1. Characteristics of the sample villages

Our survey concerns a sample of 36 villages, chosen from five willayates (districts) in Western Algeria; 30 of the sample villages were electrified of which 14 after 1977. A distinction was made between traditional and socialist villages so as to try and assess the extent to which the impact of electricity is influenced by other rural development inputs; there were 14 socialist villages in the sample and 22 traditional villages including the six without access to electricity. Other characteristics of the sample villages are summarised in Table 4.1; more details on sampling may be found in the Annex.

Table 4.1

Characteristics of 36 sample villages

	Number of sample villages
Population	
- under 500	8
- 500 to 2,000	20
- over 2,000	8
Distance to the nearest town	
- less than 10 km	16
- 10 to 50 km	17
- more than 50 km	3
Predominant economic activity	
- agriculture	30
- animal husbandry	4
- industry	2
Location	
- plains	25
- mountains	3
- hills	4
- oasis	4

Once the sample villages had been identified, households and establishments were in principle selected at random. However, when adequate cooperation could not be obtained from the selected unit, a more cooperative one was substituted in order to ensure a 100 per cent rate of response. It was found that 282 (or 94 per cent) of the 300 sample households in electrified villages, and 73 of the 100 establishments in these villages used electricity. The relatively lower rate for establishments is explained by the fact that only 11 of the 34 farms and agricultural units had a connection. This may be so because some of these farms were located outside the village boundaries making a connection more expensive while there was not enough need for electricity. In any event, connection rates appear to be on the whole quite high.

Estimates of consumption suggest that in particular the households benefit from electrification; the share of agricultural and industrial units in total consumption is very small. Villages as a whole may benefit from the use of electricity for lighting streets; in 13 of the 30 villages all streets appear to have public lighting from the grid.

From our interviews with leading villagers, usually local council members, it appeared that in 13 out of 30 villages and irrespective of the distance between the village and the nearest town, economic development was seen to be the major benefit of electricity. Improvements in the quality of life were seen as the major benefit in 9 villages, reduced migration in 4 villages and additional employment in 3 of the 30 electrified villages. It may be worth noting that reduced migration came out first in three of the 14 villages which were less than 10 km from the nearest town.

Our village-level interviews were meant to sollicit general opinions and perceptions prevailing in each of the sample villages. As results are likely to be biased by the personal views of the respondents, they should be handled with care. From the village point of view, one appeared to be more than satisfied with electricity as a source of energy and with the quality of the services provided by SONELGAZ. Only two out of 30 villages were not satisfied; the fact that these were relatively far away from the nearest town need not be significant, but might indicate that maintenance problems, and breakdowns therefore, are more frequent when electricity is supplied to more remote villages.

The average cost of electrification per household certainly varies per village depending on the distances involved and in particular, the number of connections. The PNE estimates that half of all the centres which remained without electricity in 1978 had less than 50 households. Costs are said to vary from 2,000 DA per household in large centres to 35,000 DA or more for isolated homes; the average is around 4,500 DA.[15]

4.2. Characteristics of the sample households

Our household sample consisted of 300 households in electrified villages and 60 in non-electrified villages. As 18 households in electrified villages were not connected to the grid, there were 78 households without electricity in the sample.

The average size of the sample households was just over 7 which corresponds with the national average.[16] Most heads of households were male, in the 35-54 age bracket and wage earners in the agricultural sector; they were usually the only income earner in the household.

Table 4.2 presents information on household incomes. Over 80 per cent of the sample earned less than 2,400 DA (US$ 500) per month. There is a distinct difference between households with and without electricity. Some 48 per cent of households with, as compared to 70 per cent of households without electricity earned less than 1,200 DA per month; 18.7 per cent of the households with, as compared to 2.6 per cent of the households without electricity earned more than 2,400 DA per month.

Almost 80 per cent of the sample households own the house in which they live and an equal proportion of houses is made of stone, two factors which no doubt contribute to high connection rates.

4.3. Households without electricity

We interviewed 18 non-user households in electrified villages and 60 households in villages which were not yet electrified. Most of the former category explained that their application to be connected was being held up, that they were still in the process of building their house, or that they were too far from the grid. Three of the 18 mentioned the high cost of a connection and only one the high cost of electricity. It may be noted that connection costs had recently been increased to 400 DA. This is no doubt a

Table 4.2

Monthly income of sample households

Income range (DA)	Number of households				Total	
	Households with electricity		Households without electricity			
	No.	%	No.	%	No.	%
Less than 1,200	135	47.9	54	69.2	189	52.5
1,200 - 2,400	84	29.9	21	26.9	105	29.2
2,400 - 4,800	41	14.5	2	2.6	43	11.9
4,800 - 9,600	12	4.2	-	-	12	3.3
9,600 and more	-	-	-	-	-	-
No response	10	3.5	1	1.3	11	3.1
Total	282	100.0	78	100.0	360	100.0

lot of money for households which are mainly in the lowest income bracket even if each and every connection remains heavily subsidised; real costs at the time of our survey were estimated to vary between 6,000 and 7,500 DA per connection.

Almost all households without electricity use gas as an alternative. There is plenty of it, as Algeria is one of the world's biggest producers and exporters of natural gas; it is very cheap and it is either supplied via the grid or conveniently stored in bottles which one can carry anywhere. Other energy sources include candles, wood, kerosene and fuel oil (Table 4.3)

A bottle of gas contains 13 kg of liquid gas (equivalent to 17 m^3 of natural gas or 180 kWh); its price does not exceed 14 DA; on average, three bottles are used per household per month. A 1980 SONELGAZ survey found that three out of four rural households without electricity own a small gas cooker; gas is also used for lighting. The same survey shows that on average households use 37 candles per month, just over 4 litres of kerosene, and 52 'itres of fuel oil which is mainly used for heaters owned by 23 per cent of

Table 4.3

Use of alternative sources of energy by households without electricity

Energy source	Number of households	Per cent (N = 78)
Gas	72	92.3
Candles	59	75.6
Firewood	34	43.6
Kerosene	22	28.2
Others (incl. fuel-oil, batteries, carbide)	28	35.9

Note: Most households use more than one alternative.

rural households without electricity.[17] Firewood is used only occasionally and in small quantities according to our respondents. This is so because supplies are limited and woods and forests are strictly protected.

Monthly expenditure in non-electrified households on energy sources other than electricity appears relatively important. Of the 64 households responding (14 did not respond) only 23 (or 36 per cent) spent up to 50 DA and 29 households (45 per cent) more than 100 DA per month. In comparison, 69 per cent of electricity using households spent less than 50 DA per month on alternative energy sources and only 20 per cent more than 100 DA.

4.4. Households with electricity

Of the 282 sample households which used electricity 140 were in socialist villages and 142 in traditional villages. As all houses in socialist villages are from the beginning and automatically connected to the grid we asked these households why they used electricity rather than why they had opted for a connection. Convenience appears to be the main benefit which people expected from using electricity (60 per cent) followed by cheapness (19 per cent) and safety (11 per cent).

Electricity is mainly used for lighting, every day by almost all respondents. This does not mean that electrified households would not use other sources of energy for lighting. In fact, one out of two households also used alternatives, mainly gas (in 32 per cent of the households), candles (in 17 per cent of the households) and kerosene (in 2 per cent of the households). That they use these alternatives as a supplementary energy source may be seen in consumption levels: electrified households use on average 9 candles per month and 0.8 litres of kerosene as compared to 37 candles and 4 litres of kerosene in households without electricity.[18]

Electricity is hardly used for cooking and heating water; less than 6 per cent of the households used it daily for this purpose. In fact, 81 per cent of electricity using households used gas for cooking and 11 per cent used wood. The explanation is simple in that consumers realise that gas is a perfect substitute and much cheaper; moreover (or as a result) electric stoves are hard to find and if they are available, quite expensive. This situation is not confined to cooking stoves. In general it appears that 40 per cent of our respondents use alternatives because they do not have (cannot afford) electrical appliances and 32 per cent do so because they find alternative fuels even cheaper than electricity.

The use and hence the benefits of electricity may indeed be assessed in terms of the ownership, or rather the use which is made of appliances. Table 4.4 shows that lightbulbs apart, television is by far the most widely used item: as many as three out of four households use their set often. Together with the general use of electric lights, this explains why 85 per cent of the households reported that access to electricity had influenced the way in which they spent their evenings. In fact, 32 per cent of the households considered the effect on their evening activities as the main benefit from having electricity. It is evident that many people find electricity a key to additional or different kinds of entertainment, to a more intensive social life, to additional opportunities for children to do their homework, and so on and so forth.

Refrigerators are also popular judging from the fact that they are being used on a continuous basis by 60 per cent of the rural households with electricity. In a country with a hot climate the benefits of refrigeration are obvious; often the refrigerator has displaced traditional means for keeping water cool. Almost 40 per cent of the households use a radio more or less frequently. Other commonly used appliances are irons (in 29 per cent of the households), and fans (in 21 per cent of the households).

Table 4.4

Use of electrical appliances by households with electricity

Appliance	Never used		Sometimes used		Often used	
	No. of hh.	%	No. of hh.	%	No. of hh.	%
Lightbulbs/lamps	0	0.0	0	0.0	282	100.0
Television	52	18.4	9	3.2	212	75.2
Refrigerator	78	27.7	22	7.8	170	60.3
Radio	170	60.2	38	13.5	73	25.9
Iron	197	69.8	50	17.7	32	11.3
Fan	218	77.3	36	12.8	23	8.2
Record player	240	85.1	23	8.2	13	4.6
Sewing machine	241	85.5	30	10.6	8	2.8
Air conditioner	257	91.1	16	5.7	4	1.4
Power tools	252	89.4	21	7.5	4	1.4
Water pumps	262	92.9	13	4.7	2	0.7
Stove	265	94.0	12	4.3	1	0.4
Other	280	99.3	1	0.4	1	0.4

Note: Totals do not always add to 282 or 100 per cent because some households did not respond depending on the electrical appliance we asked them about.

Appliances which could be put to productive use feature lower on the list; sewing machines are used more or less often in 13.4, power tools in 8.9, and water pumps in 5.4 per cent of households with electricity. That limited use is made of electricity for productive purposes may also be concluded from the fact that only 6 per cent of the respondents said yes to the question whether they used electricity for activities which were meant to increase their income. Only 6 households (2 per cent) reported that they considered additional income as the main benefit from having electricity.

Convenience, comfort and safety are generally considered as main benefits, much in keeping with what people had expected from electricity. Cheapness of electricity was mentioned by 54 households as a reason for getting connected or for using electricity in houses which were already connected when they moved in. Only five households however, considered in retrospect that cheapness was the main benefit they derived from electricity. This may have something to do with an apparent increase in electricity consumption over the years. In any event, Tables 4.4 and 4.5 strongly suggest that people value electricity and that they are likely to use it increasingly for purposes other than lighting.

Consumption levels are of course related to income and wealth (the ownership of appliances), the price of electricity and of substitutes such as gas, and the price of appliances.

Table 4.5

Changes over time in the level of electricity consumption of households

Level of consumption	No. of households	Per cent
More than before	150	53.2
The same as before	90	31.9
Less than before	3	1.1
Do not know	30	10.6
No response	9	3.2
Total	282	100.0

No household could answer our question about the quantity of electricity consumed; in fact only very few people knew that consumption was measured in kWh. Obviously the figure which matters most on the two monthly electricity bill is the amount to be paid. We thus found that 255 of the 282 could remember how much they had to pay for electricity consumed during the previous two-month period. More than 60 per cent of the households (169) spent less than 25 DA per month whereas only 17 households spent more than 50 DA per month. Table 4.6 presents the complete data in relation to monthly income and confirms what one would expect namely that there is some relationship between income and expenditure on electricity (in fact the correlation coefficient is 0.41).

It is not evident that the amount paid should indicate directly and precisely how much electricity is consumed as tariffs vary with the circumstances. If it is roughly assumed that households paid an average of .40 DA per kWh in 1983[19] it may be concluded that the modal household consumed almost 50 kWh per month.

This figure (which should be treated with caution) appears to be relatively high e.g. in comparison with estimates in the PNE which suggest that consumption will be between 250 and 500 kWh per connection per year or between 20 and 40 kWh per month. The 1980 SONELGAZ study on rural electrification suggests that consumption varies mainly with village size between 30 and 60 kWh per person per year which would correspond to a range of 17 to 35 kWh per household per month.

Most of our respondents were in fact pleased with the price of electricity. As many as 43 per cent of the households found it cheap, 25 per cent believed that the price was right and another 25 per cent found electricity expensive (7 per cent did not respond). In Table 4.7 the opinion on the price of electricity is presented according to levels of expenditure on it. It may be noted that households which found electricity expensive tended to spend more on it than other households; inversely, 70 per cent of those who found electricity very cheap spent less than 25 DA per month on it. These are indications to suggest that households value the service highly and/or that they would be prepared to pay more for their electricity.

Consumer appreciation is also seen in the response to a question about the quality of electricity supply: 37 per cent of the consumers were more or less satisfied and more than half of them very satisfied (Table 4.8). It should be noted that such perceptions may concern satisfaction with electricity as a source of energy, satisfaction with the service provided by SONELGAZ or both; it is difficult indeed to separate the two.

Table 4.6

Expenditure on electricity and household income per month (DA)

Monthly Expenditure on Electricity	Households monthly income					
	less than 1200	1200 to 2400	2400 to 4800	4800 to 9600*	No response	Total
Less than 12.50	42 (31.1)	16 (19.0)	4 (9.8)	-	1 (10.0)	63 (22.3)
12.50-25.00	44 (32.6)	38 (45.2)	16 (39.0)	1 (8.3)	7 (70.0)	106 (37.6)
25.00-37.50	44 (17.8)	11 (13.1)	9 (21.9)	1 (8.3)	1 (10.0)	46 (16.3)
37.50-50.00	11 (8.1)	6 (7.1)	2 (4.9)	3 (25.0)	1 (10.0)	23 (8.2)
50.00-62.50	5 (3.7)	-	3 (7.3)	2 (16.7)	-	10 (3.5)
62.50-75.00	1 (0.7)	-	-	2 (16.7)	-	3 (1.1)
75.00-87.50	1 (0.7)	-	-	-	-	1 (0.3)
87.50-100	1 (0.7)	-	-	-	-	1 (0.3)
100 and higher	-	-	1 (2.4)	1 (8.3)	-	2 (0.7)
No response	6 (4.6)	13 (15.6)	6 (14.7)	2 (16.7)	-	27 (9.7)
Total	135	84	41	12	10	282

*Note: there are no households with an income over 9,600 DA.

Table 4.7

Expenditure and opinion on the price of electricity

Expenditure (DA per month)	Opinion (no. of households)					Total
	Very cheap	Cheap	Right	Expensive	No response	
less than 12.50	19	12	18	11	3	63
12.50-25.00	43	15	24	21	3	106
25.00	13	11	26	34	2	86
no response	2	6	3	3	13	27
Total	77	44	71	69	21	282
	(27)	(16)	(25)	(25)	(7)	(100)

Note: Figures in brackets are percentages.

Table 4.8

Perceived satisfaction with the service

	No. of households	%
Very satisfied	159	56.4
More or less satisfied	105	37.2
Not satisfied	10	3.5
No response	8	2.9
Total	282	100.0

As has already been mentioned, households with electricity also use other sources of energy for various reasons and for different purposes. Their expenditure on other energy sources is summarised in table 4.9. It appears that two out of three households with electricity pay in between 10 and 50 DA per month for these other sources of energy; 28 per cent pay between 20 and 30 DA per month. Levels of household income hardly influence expenditure on sources of energy other than electricity, or so it appears. It is likely that comparable quantities of electricity and alternative energy sources are used for meeting the basic energy needs of the electrified household, notably lighting and cooking. Additional needs tend to be met by using more electricity rather than alternatives which is borne out by the correlation which exists between income and expenditure on electricity.

Table 4.9: Monthly expenditure on energy sources other than electricity in electrified houseolds by broad income categories

Monthly expenditure (DA)	Monthly Household Income (DA)					Total	
	less than 1200		1200 or more		no response		
	hh	%	hh	%	hh	hh	%
less than 10	-	-	-	-	1	1	.4
10 - 20	6	4.4	10	7.3	2	18	6.4
20 - 30	39	28.9	37	27.0	2	78	27.7
30 - 40	22	16.4	19	13.9	-	41	14.5
40 - 50	29	21.5	27	19.7	-	56	19.8
50 - 100	11	8.1	16	11.7	3	30	10.6
more than 100	28	20.7	28	20.4	1	57	20.2
no response	-	-	-	-	1	1	.4
Total	135	100.0	137	100.0	10	282	100.0

In table 4.10 expenditure on electricity is compared with expenditure on alternative energy sources in households with and without electricity. The following broad conclusions would seem to emerge:

- Households without electricity spend more on alternative sources of energy than electrified households spend on either electricity or alternative sources;
- More than half of the electrified households spend about as much on electricity as on alternative energy sources; 21 per cent spend more on electricity than on alternatives and 26 per cent spend less.

Table 4.10: Expenditure on electricity and alternative energy sources in electrified and non-electrified villages

Expenditure on alternative sources	non-electrified households		electrified households by expenditure on electricity				
	TOTAL		TOTAL		50DA	50-100DA	100DA
	hh	%	hh	%	%	%	%
less than 50 DA	23	35.9	175	68.6	48.2	17.3	3.1
50 - 100 DA	12	18.8	29	11.4	8.6	2.4	.4
More than 100 DA	29	45.3	51	20.0	9.4	7.5	3.1
Total	64	100.0	255	100.0	66.2	27.2	6.6

Note: This table has been corrected for non-response assuming that non respondents are representative for the sample in terms of their expenditure on electricity and other sources of energy. Of 78 non-electrified households 14 did not respond to the question about expenditure on alternative energy sources. Of 282 electrified households one did not respond to the same question and 26 had no answer to the question about expenditure on electricity. Of these 26, 19 spent less than 50 DA, one between 50 and 100 DA, and six more than 100 DA on alternative energy sources.

CHAPTER 5

THE SOCIO-ECONOMIC IMPACT OF RURAL ELECTRIFICATION ON ESTABLISHMENTS

5.1 Characteristics of the sample establishments

Particularly in order to obtain a picture of electricity use for more or less productive purposes, our survey included a sample of 110 establishments, 73 of them with and 37 without electricity, 100 in electrified and 10 in non-electrified villages. The establishments included 34 agricultural and 8 industrial units, and further a variety of 29 commercial units, shops in particular, and 39 public service units such as schools, clinics, mosques and public baths.

We consider the distribution as a whole fairly representative. Industry in Algeria has seen a rapid expansion in the last two decades, but industrial units tend to be concentrated in selected areas such as Arzew in the West and Skikda in the East of the country and for the rest in and around major cities. In other words, rural industrialisation is not a widespread phenomenon.

About half of all establishments had five workers or less; another 25 per cent employed between six and 20 workers; and the remaining 25 per cent employed more than 20 workers. Our results suggest that establishments with electricity tend to be somewhat smaller than those without it. A preference for electricity use in shops could offer an explanation, although the size of our sample may also be involved.

The predominance of relatively small establishments is confirmed in a summary of their annual earnings. Because the data are no doubt suffering from some under-reporting and a high non-response rate for establishments without electricity, and because there is a significant number of establishments of the non-earning type (which effectively reduces the size of our sample) it is difficult to say something about the difference in earnings between establishments with and without electricity. It is nonetheless worth noting that 31 establishments earn less, and 36 more than 50,000 DA (some

Table 5.1: Annual earnings of sample establishments

Annual earnings ('000 DA)	Establishments with electricity No.	%	Establishmnts without electricity No.	%	Total No.
Less than 10	-	-	1	2.7	1
10 - 25	6	8.2	2	5.4	8
25 - 50	17	23.3	5	13.5	22
50 - 100	8	10.9	3	8.1	11
More than 100	12	16.4	13	35.1	25
not applicable	29	39.7	4	10.8	33
no response	1	1.5	9	24.3	10
Total	73	100.0	37	100.0	110

US$10,000) per year. Establishments without electricity would on average seem to earn as much as and possibly more than the ones with electricity.

Most of our sample establishments (60 per cent) started operating after 1970 (1982 was our latest date) and in particular after 1978 (40 per cent). This may no doubt be related to an increasing emphasis on rural development in Algerian policies but it would go a bit far to associate the fact merely with the launching of the National Electrification Plan (PNE).

Our data do not suggest that establishments without electricity are necessarily smaller or earning less than the ones with electricity: they may be small shops or big farms, industrial units or dispensaries. In non-electrified villages the reason for not using electricity is evident. In villages with electricity non-use appeared to be mainly the result of administrative delays. Financial considerations did play no major part except in the case of farms which were far away from the village.

All establishments without electricity said that they would use it if it were available. Several reasons for wanting to use electricity were advanced notably that electricity would save time and money. Five of the 27 non-users in electrified villages mentioned that they would like to use new machinery, due perhaps to competitive pressure on them by electricity users; water pumps, welding equipment, grinding machines and cold storage equipment were singled out.

5.2 Establishments using electricity

Table 5.2 indicates that all 73 establishments with electricity used it for lighting and 80 per cent of them used it mainly for lighting. Refrigeration was the second most popular use of electricity; 47 per cent of the establishments used electricity for that purpose and 11 per cent of the establishments mainly so. These include in particular shops which sell meat and dairy products. Almost 20 per cent of the establishments use electricity for machines including welding equipment and electrical saws.

Only three establishments used an electric pump for irrigation purposes which confirms that farms make a rather limited use of electricity for productive purposes. This may be so because they do not irrigate their land or because they do so with alternative energy sources. The SONELGAZ study already referred to[20] found that in electrified areas only 40 per cent of the pumps used were electric pumps.

Table 5.2: Use of electricity

Use	Main use		Other use		Total	
	no. of est.	%	No. of est.*	% (N=73)	No. of est.*	% (N=73)
Lighting	58	79.5	15	20.5	73	100.0
Refrigeration	8	11.0	26	35.6	34	46.6
Heating	1	1.4	3	4.1	4	5.5
Pumps	1	1.4	2	2.7	3	4.1
Machinery	5	6.8	9	12.3	14	19.2
Other	-	-	10	13.7	10	13.7
Total	73	100				

* Some respondents cited more than one answer.

Table 5.3: Monthly electricity consumption of sample establishments

Monthly consumption		Establishments	
DA	kWh	No.	Per cent
Less than 12.50	Less than 40	9	12.3
12.50-25.00	40-80	16	21.9
25.00-50.00	80-160	9	12.3
50.00-75.000	160-240	5	6.8
75.00-100.000	240-320	4	5.5
100.00-150.00	320-480	4	5.5
150.00-250.00	480-800	4	5.5
More than 250.00	More than 800	9	12.3
No response	-	13	17.8
Total		73	100

Most respondents did not know how much electricity they consumed, that is in terms of kWh and asking them for their latest bill was on the whole fruitless. But most appeared to know precisely how much they had paid for electricity. As tariffs vary e.g. depending on consumption levels and on day or night use, it is not easy to translate expenditure into units of consumption. However, we have made an attempt by assuming an average price of 0.3125 DA/kWh.

It appears that at least one third of the establishments pays less than 25 DA per month which corresponds with a consumption of less than 80 kWh/month. Half of all establishments pay less than 50 DA (160 kWh/month). These consumption levels naturally reflect the fact that the establishments are relatively small and that most of them use electricity mainly for lighting.

Further analysis reveals that establishments set up before 1977 use on average more electricity than those which started operating more recently. A suggestion which is implied, namely that electricity consumption is likely to grow over the years, is more or less confirmed by our respondents. Of the 61 establishments who could answer our question 24 (40 per cent) reported that they used more electricity every year and only 4 reported a decrease. This leaves more than half of the establishments whose consumption does not apparently change over time. A shortage of electrical equipment in local markets may be part of an explanation.

The price of electricity does not seem to be a hindrance. Almost half of those with an opinion on the price of electricity found it cheap or even very cheap and very few respondents found electricity expensive (table 5.4).

Table 5.4: Opinion on the price of electricity

Opinion	Establishments	
	Number	%
- Very cheap	11	15.0
- Cheap	18	24.7
- Right price	31	42.3
- Expensive	2	2.7
- Very expensive	2	2.7
- No response	9	12.6
Total	73	100.0

Larger establishments with higher annual earnings are likely to spend more on electricity than smaller ones, but correlation is far from perfect. Out of 43 "earning" establishgments, six earned less than 25,000 DA per year and all six spent less than 25 DA/month on electricity. Eleven of 17 in the 25-50,000 DA bracket also spent less than 25 DA/month. Of 12 establishments earning more than 100,000 DA per year six spent more than 250 DA/month on electricity (two respondents in this group didn't know).

Electrified establishments are in large number very satisfied with their electricity as well as the service provided by the utility corporation; only two establishments were not satisified as they had suffered from frequent cuts (table 5.5).

Table 5.5: How satisified are establishments with electricity and the quality of the service

Level of satisfaction	Establishments Number	%
- Very satisfied	37	50.7
- More or less satisified	28	38.4
- Not satisified	2	2.7
- No response	6	8.2
Total	73	100.0

5.3 The use of alternative sources of energy

Almost all establishments, electrified or not, use energy sources other than electricity in particular gas and diesel mainly for cooking and heating. Gas which is abundant and cheap is supplied through a relatively dense grid and in bottles. It is used in 41 per cent of the establishments with, and in 46 per cent of the establishments without electricity. Animals are an important source of energy in non-electrified establishments. However, the horses and mules which are commonly used for ploughing and carrying loads cannot be considered as substitutes for electricity; they are therefore also used in electrified establishments, depending on the nature of the enterprise. Alternatives to electricity for lighting are only used in a few non-electrified establishments; in fact many establishments operate during daylight hours only (tables 5.6 and 5.7).

Table 5.6: Energy sources other than electricity used in establishments with and without electricity

Energy source	Establishments with electricity Number	Per cent (N=73)	Establishments without electricity Number	Per cent (N=37)
Gas	30	41.1	17	45.9
Diesel	25	34.2	12	32.4
Animals	7	9.6	14	37.8
Kerosene	-	-	3	8.1
Wood	3	4.1	2	5.4
Other (mainly fuel oil)	5	6.8	8	21.6
None	10	13.7	1	2.7

Note: Some establishments use more than one alternative energy source.

Table 5.7: Purpose of using alternative energy sources in establishments with and without electricity

Purpose	Establishments with electricity Number	Per cent (N=73)	Establishments without electricity Number	Per cent (N=37)
Cooking/heating	37	50.7	25	67.6
Lighting	-	-	5	13.5
Machinery	2	2.7	1	2.7
Irrigation pumps	1	1.4	2	5.4
Tractors/motorvehicles	4	5.4	3	8.1
Animal drawn implements, carts	7	9.6	14	37.8

Note: Some establishments use alternative energy sources for more than one purpose

Monthly expenditure on alternative energy sources by establishments with and without electricity are summarised in table 5.8. It appears that the average establishment without electricity spends more on alternatives than the electrified establishments: 60 per cent of repondents without, against 40 per cent of establishments with electricity spent more than 250 DA per month. If one would add what electrified establishments spend on electricity (see table 5.3), one would find that such establishments tend to spend more on all energy sources combined than the non-electrified establishments.

Table 5.8: Monthly expenditure on energy sources other than electricity by establishments with and without electricity

Expenditure	Establishments with electricity			Establishments without electricity		
	No.	%	%*	No.	%	%*
Not applicable**	16	21.9	31.4	2	5.4	7.7
Less than 50	6	8.2	11.8	4	10.8	15.4
50-150	7	9.6	13.7	4	10.8	15.4
150-250	2	2.7	3.9	1	2.7	3.8
250-500	9	12.3	17.6	7	18.9	26.9
More than 500	11	15.0	21.6	8	21.6	30.8
No response***	22	30.3	-	11	29.7	-
TOTAL	73	100.0	100.0	37	100.0	100.0

* corrected for non response

** includes those spending nil because they consume no alternatives; moreover expenditure on animal power (e.g. extra fodder) has not been considered; may also include free energy e.g. wood.

***Many respondents, however cooperative, didn't know.

5.4 Impact of electricity

It is certainly not easy to isolate the impact of using electricity rather than alternatives on what happens in establishments. Asked whether they would have started operating if there had been no electricity, most repondents were not sure what to answer. For some, such as heads of public services, the question made little sense as they had not been involved in the decision to set up their school or clinic; in any case, access to the grid would seem a truly marginal factor in such decisions.

About half of the establishments in our sample started operating after electricity was introduced in the village which may be an indication of the "attractiveness" of electricity. It is impossible to suggest however, that these establishments, mainly small shops, would not have come into being without rural electrification. Moreover the 14 socialist villages in our sample of 30, never existed without electricity.

We therefore asked establishments about changes which occurred in the various inputs and outputs after electricity was introduced; their answers are in table 5.9. It is particularly worth noting that a large number of respondents believed that some or all of our questions about change did not apply to their situation. There are of course no profits in non-profit establishments, or sales for that matter; and working hours for public establishments are uniformly fixed. In other instances respondents could not conceive of a relationship between their using electricity and changes e.g. in skill requirements, the number of accidents or the number of workers they employed.

Table 5.9

Impact of electrification on operations of sample establishments

	Much more	A bit more	About the same	A bit less	Much less	Not appli-cable	No response	Total
Number of machines	13 (17.8%)	11 (15.1%)	10 13.7%)	- -	2 (2.7%)	28 (38.4%)	9 (12.3%)	73
Number of workers	2 (2.7%)	11 (15.1%)	16 (21.9%)	1 (1.4%)	2 (2.7%)	32 (43.8%)	9 (12.3%)	73
Hours worked	15 (20.5%)	15 (20.5%)	11 (15.1%)	4 (5.5%)	1 (1.4%)	18 (24.7%)	9 (12.3%)	73
Output/ sales	10 (13.7%)	5 (6.8%)	9 (12.3%)	1 (1.4%)	1 (1.4%)	38 (52.1%)	9 (12.3%)	73
Profits	4 (5.5%)	8 (10.9%)	9 (12.3%)	2 (2.7%)	1 (1.4%)	40 (54.8%)	9 (12.3%)	73
Number of accidents	2 (2.7%)	1 (1.4%)	12 (16.4%)	1 (1.4%)	10 (13.7%)	38 (52.1%)	9 (12.3%)	73
Skill re-quirements	8 (10.9%)	5 (6.8%)	7 (9.6%)	-	-	44 (60.3%9	9 (12.3%)	73

That being said, it appears that electricity did have an impact on working hours in almost half of the establishments responding to this question. The possibility of working after dark is particularly relevant in the southern and Saharian regions of the country where heat compels many establishments to be closed for part of the day. For example, work on construction sites used to be often interrupted for unbearable heat. With the introduction of electricity it became possible to work at night using floodlights. As a result work improved a great deal both in terms of quantity and quality.

Access to electricity has furthermore had some impact on the number of machines used in the establishments. The fact that machines are also used in public services (e.g. hospitals) may explain why output and profit have been relatively less affected. It cannot be concluded with confidence that electricity use has had a positive impact on employment but the number of respondents who said that the number of workers had somewhat increased is worth noting. On balance it would seem that electricity has contributed to reducing the number of accidents which confirms the common opinion that electricity is a safe energy source.

CHAPTER 6

SUMMARY OF FINDINGS AND CONCLUDING REMARKS

Algeria has made a remarkable progress in rural electrification in recent years in consequence of a deliberate policy on the part of the Government, reflected in the National Electrification Plan, to extend the benefits of electricity to every inhabitant even in remote rural areas. Major investments in rural electrification were possible as a result of important oil revenues particularly during the 1970s. Algeria's electricity grid now covers most of the country, but village electrification rates vary from one area to another.

Rural electrification is seen as a means to achieve political, social and economic goals and as a means to solve some of the problems of rural people which often result in migration to already crowded urban centres. The emphasis is deliberately on social objectives, on improving the quality of rural life and on achieving greater equity between urban and rural areas. Objectives such as increasing rural output through electrification appear to take a second place.

Considering that its real costs are beyond the means of most rural people, rural electricication remains heavily subsidised by the State; electricity is thus included among the essentials for decent living such as food, drinking water, health care and schooling.

Together with electricity, gas has been heavily introduced in rural areas through a dense distribution grid and in bottles. This appears to have contributed to reducing the use of non-commercial sources of energy such as collected firewood which is considered important in view of protecting the forests from rapid degradation.

Electricitation in Algeria is often part of other rural development efforts such as schemes for housing, sanitation, drinking water, roads and other types of infrastructure. The ultimate example of a comprehensive approach is found in the building of entirely new villages fully equiped with all the amenities of modern living and better known as the Socialist Villages. In such circumstances it is difficult, to say the least, to isolate the socio-economic impact of rural electrification. On the other hand, impact would probably be less significant in the absence of other efforts.

The impact of rural electrification on production and productivity, on employment and on income, may therefore not be easily established. However, the necessary investments have undoubtedly contributed to the creation of employment within the energy sector first of all, as a sizeable labour force had to be mobilised to implement the National Electrification Plan. Secondly, they have contributed to the creation of employment and income in industries producing poles, wires and cables, transformers, switchgears and insulators, as well as electrical appliances and other kinds of equipment which are gradually being made locally to substitute for imports.

Connection rates are high whereever electricity is available in rural Algeria. The total number of rural establishments including farms, industries, commercial units and public services is relatively limited however, and so is their share in electricity consumption. Households represent by far the highest proportion of electricity consumers and it is therefore at this level that the impact of electrification should be the most evident.

At the level of the village, street lights are generally appreciated. People feel more safe when moving around particularly in winter when it gets dark early; shopowners naturally hope to benefit from extended opening hours; social life is enhanced as people meet more often; and electricity also permits new forms of entertainment. There is little evidence however to suggest that electrification has caused a reduction in rural-urban migration. There are no doubt other push and pull factors involved in that phenomenon, notably opportunities for schooling and employment of young people.

Our comparison of socialist and traditional villages did not reveal major differences in terms of the impact of electricity use. People in both kinds of villages equally enjoyed having access to electricity but its productive use is generally limited; this may be explained by the fact that the people who moved to the recently established socialist villages need time to adapt their habits and attitudes to new opportunities. In other words, one should not expect the effect of comprehensive rural development schemes to be immediate.

Households appear prepared to contribute a large sum towards the costs of their connection to the grid, that is relative to their monthly income rather than to the true cost of such a connection. This may be so because most households find electricity cheap; that households believe to get value for their money is confirmed by the fact that a large majority of them is more than satisfied with electricity and the service provided by SONELGAZ.

Electricity has not totally displaced other energy sources. Cooking is in fact almost exclusively done on gas both in households with and without electricity. Gas is plentiful, flexible and cheap and thus able to compete with electricity. But in the case of lighting electricity consumers have in large numbers done away with kerosene and candles which are still being used in non-electrified households.

Most electrified households spend roughly equal amounts on electrificy and on other sources of energy. As incomes grow, it appears that electricity consumption also rises though not proportionately. Our data further suggest that households without electricity spend more on alternative sources of energy than electrified households spend on either electricity or alternative sources; the total energy bill of the average electrified household is higher however than the energy bill of the average household without electricity.

Rural households are in large numbers convinced of the convenience, safety and comfort which electricity provides. In addition to appreciating a better quality of light, they benefit from (or merely enjoy) watching television and keeping food and drinks cool in their refrigerator. The apparently widespread ownership of television sets and refrigerators represents an important indirect socio-economic effect of rural electrification, namely employment and earnings in the domestic industries which produce such appliances. Other uses of electricity remain rather limited even if consumption per household increases over time. Only a few households use electricity for productive purposes such as sewing or irrigation. As a result the direct employment and income effect of using electricity at home is truly limited.

The use of electricity in establishments is not necessarily or only serving productive purposes and the economic impact of electrification is accordingly modest. We have in any case not been able to discern a significant effect on output and productivity or on employment and earnings.

With a few exceptions electricity is used mainly for lighting even in establishments which by their nature might put it to different use. Refrigeration, however, is also a common purpose of using electricity notably in shops. Only 3 out of the 73 sample establishments with electricity used an electric pumpset for irrigation and 14 (less than 20 per cent) used electricity to operate other machines e.g. for welding or sawing. Consumption levels are relatively low; half of all establishments spent less than 100 DA/month which corresponds to about 300 kWh.

The price of electricity does not apparently present a hindrance to using more of it; less than six per cent of the establishments found electricity expensive. But gas is also cheap and used therefore in more than 40 per cent of the establishments with electricity.

Limited use of electricity for only a few purposes is in part a reflection of the fact that most establishments in rural areas are small. About half of the establishments in our sample had five workers or less. Limited supplies of electrical appliances and their relatively high cost have also played a role in keeping electricity consumption from increasing faster. Current policies to overcome such problems will no doubt help to enhance returns from electrification. In any event there would seem to be considerable scope for increasing awareness among rural establishments of the potential benefits they might derive from making a more productive use of electricity.

To conclude, the introduction of electricity in rural areas has made a significant difference to the people there. It has made life easier and more comfortable at a price which most can afford. A large proportion of households in electrified villages is connected and consumption, while still modest, is gradually increasing. People in rural areas are right to consider and enjoy electricity as one of the fruits of independence.

There is nonetheless scope, it appears, to augment the returns from the remarkable effort. It would, to begin with, be advisable to monitor the relationship between various costs and benefits in a more thorough and systematic fashion. In addition to ex-ante project appraisal, regular ex-post evaluations would allow one to identify opportunities to cut costs and to increase benefits. For the massive investments to bear more fruit, load development measures should be particularly aimed at farms and rural industries with a view to increasing the economic benefits of rural electrification. There is little gain to be expected from promoting electricity consumption for its own sake and measures to conserve energy are not necessarily in conflict with the objectives underlying rural electrification.

References

1. In 1978, the developing countries imported 47 per cent of the gas turbines and 65 per cent of the steam boilers in the world, 56 per cent of the insulated wires and cables and 37 per cent of the switch gears. In all nearly 12,000 million US$ of power equipment were imported. See UNIDO, "Investment requirements of developing power industries for the industrialisation of developing countries", UNIDO/IS.359, December 1982.

2. SONELGAZ, "Project Electrification, programme pluriannuel: 1982-1983-1984", Ministere de l'Energie et des Industries Péetrochmiques, Alger, Oct. 1981.

3. The data in this paragraph are based on: World Bank, World Development Report 1984.

4. See: SONELGAZ, "Plan National d'Electrification" (PNE), Ministere de l'Energie et des Industries Pétrochimiques", Alger, 1978, pp. 11-12.

5. See: United Nations, 1982 Yearbook of World Energy Statistics, New York 1984.

6. A. Benachenhou, L'exode rural en Algérie, SNED, Alger, 1978, p. 139.

7. Translated from the French. The first four year development plan (1970-1973) was prepared by the Secretariat d'Etat au Plan (SEP). In the 1980s Algeria adopted two 5-year plans prepared by the Ministere de Planification et de l'Amenagement du Territoire.

8. See: Ministére de Planification et de l'Amenagement du Territoire, Rapport général du plan quinquennal 1980-1984.

9. KAHRIF stands for Kahraba Rifia which is the Arabic for rural electrification.

10. El Moudjahid, 6 May 1984. El Moudjahid is a major national daily newspaper published in French.

11. See SONELGAZ, PNE, op. cit. pp. 26-28, and the report by a team of researchers from the Centre de Recherche en Economie Appliquée (CREA) in Algiers: I. Khennas et al., "Politique énergétique et production d'electricité en Algérie", CREA, Alger, 1982.

12. El Moudjahid, 6 May 1984.

13. See Khennas et al. op. cit.

14. El Moudjahid, 6 May 1984.

15. PNE op cit., pp. 8-9; prices of 1976; 1 DA = US$.213.

16. See for example, Enquete main d'oeuvre et demographie: estimation de la population de quelques communes" in Statistiques (a publication of the National Statistical Office) No. 1, 1983, pp. 76-77.

17. See SONELGAZ, "Projet Electrification" op. cit.

18. Ibid.

19. Cf. SONELGAZ, Statistical Bulletin for 1983, p. 11.

20. SONELGAZ, "Projet Electrification" op. cit.

SESSION 22:

SYSTEM IMPACT AND PLANT RELIABILITY

Chairperson: J. Mitchell
Ontario Hydro

Small Hydro at Newfoundland Light & Power Company Limited

By
A.W. Greeley

27

NEWFOUNDLAND LIGHT & POWER CO. LIMITED
ST. JOHN'S, NEWFOUNDLAND
SMALL HYDRO
AT
NEWFOUNDLAND LIGHT & POWER CO. LIMITED

NEWFOUNDLAND LIGHT & POWER CO. LIMITED
ST. JOHN'S, NEWFOUNDLAND

SMALL HYDRO
AT
NEWFOUNDLAND LIGHT & POWER CO. LIMITED

Prepared by:
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1988 06 28

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ABSTRACT

In 1978, Newfoundland Light & Power Co. Limited, still operated 21 of its 22 small hydroelectric plants built between 1900 and 1961. At this time the large increase in the use of electricity in Newfoundland combined with the renewed interest in renewable energy sources on a worldwide basis encouraged Newfoundland Light & Power to upgrade and rehabilitate its existing developments and investigate sites for new construction.

Since 1978 over $20 million has been spent on rehabilitation of existing sites, construction of a new 1 MW site and investigation of additional sites.

This paper will detail our experiences with small hydro over the past 8-9 years and what our investigations indicate as future potential. In particular, the many civil, electrical and mechanical problems and concerns which arose during the rehabilitations will be discussed along with the solutions to the problems referencing specific projects. Some of the concerns encountered include environmental approvals, economics of rehabilitation, utilization of existing facilities, evaluating manufacturer's guarantees, maintaining fish habitat and reconstruction of upstream hydraulic structures to present day standards.

In addition, this paper will also discuss the opportunities for future development of small hydro in Newfoundland, including a review of potential sites and the physical, environmental and economic factors affecting development.

I. INTRODUCTION

Newfoundland Light & Power Co. Limited is a privately owned utility distributing electrical energy to all major centres in Newfoundland, Canada's most eastern province.

The original company was incorporated in 1885. In 1966, with completion of a provincial energy grid, several smaller independent companies amalgamated to form the Newfoundland Light & Power of today.

The Company owns and operates 22 small hydroelectric plants throughout Newfoundland ranging in size from 400 kw to 12,750 kw. A multidiscipline staff of professionals and support staff has developed expertise in civil, electrical, and mechanical systems associated with small hydro.

In 1979, Newfoundland Light & Power Co. Limited began a complete review of its hydroelectric facilities to determine their condition after years of little or no attention, to determine ways of improving efficiency and output, and to determine if sites could be redeveloped to increase output.

This study resulted, at an approximate cost of $20.0 million, in the redevelopment of several small plants including Topsail, Lawn, Lookout Brook, Rattling Brook and Petty Harbour, the construction of a new 1 MW site at Mobile and investigation of additional sites.

This paper will outline the work carried out at some of the major projects and the possibilities for additional small hydro sites in Newfoundland. In particular an attempt will be made to outline the problems which could be experienced with rehabilitation projects referencing our experiences over the past 10 years.

In addition, the search has been ongoing for new small hydro sites. Work has included a desk-top inventory from 1:50,000 scale mapping identifying 120 sites, field visits and prefeasibility studies for over 40 selected areas. We plan to continue our work with small hydro and other renewable and alternate energy sources; and will outline in this paper some of the areas of potential in Newfoundland, the incentives and drawbacks to such development.

II. TOPSAIL PLANT

This project, located on the Avalon Peninsula, near St. John's was commissioned in 1932. The masonary powerhouse contained a single horizontal Francis unit operating under a head of 103 m.

Water supply to the project was regulated by three storage structures and a diversion structure. The water from the forebay was delivered to the powerhouse by a 1890 m long 914 mm diameter woodstave pipeline.

In 1981, the woodstave penstock was replaced after 50 years of service. Reconstruction of the penstock also included reconstruction of the intake, gatehouse and power canal.

In 1983 the old 1200 kw unit was replaced with a 2375 kw francis unit supplied by Barber Hydraulic Turbine. The unit was rated at a head of 87 m and a discharge of 3.1 m^3/s.

Additional work in 1986 and 1987 in the Topsail watershed included reconstruction of two upstream timber-crib control structures. Both structures were rebuilt as timber crib.

The work in this watershed clearly illustrates the problems which can occur when development encompasses a site. Topsail was constructed in 1931 when the area was almost wilderness. In 50 years a large town including roads, houses, a float plane base, with recreational use of the watershed, has grown up around the structures.

The woodstave penstock was replaced in 1981 with another woodstave pipe mainly because of the winding narrow route available for construction. Due to development over the years access was available at three locations only. This made removing the old pipe and constructing a new pipe very slow and difficult.

At one location, where the penstock intersects the Conception Bay highway, which had been upgraded several times over the years, it became impossible to erect the pipe with the required minimum radius. This resulted in a massive concrete anchor block. This was not part of the original plan.

Excavation for the penstock became very difficult when we were bounded on one side by the river and on the other side by private property. This condition resulted in numerous delays and costs when excavations for the penstock resulted in loss of water to surrounding homes.

Newfoundland Light & Power Co. Limited has no objections to the use of woodstave penstocks. In fact, we continue to use them when they are priced competitively and are happy with their performance. However, in a situation such as Topsail, space and access restrictions made the use of any other pipe material impractical.

Problems were encountered due to development during reconstruction of upstream control structures. One of the reservoirs is now used extensively as a summer cabin area while the other reservoir is used as a float plane base. Because of these additional uses, drawdown of the reservoir was restricted resulting in additional dewatering costs. The drawdown of the reservoirs for production is also severely restricted.

The work at Topsail clearly pointed out the affect development of surrounding properties can have on future projects and rehabilitation. Control of the watershed must be maintained or future rehabilitation of a site will be severely restricted or eliminated.

At Topsail, the old turbine generator was replaced with another unit with double the capacity and double the discharge. This additional capacity was possible because of the development of additional structures and diversion over the years without increasing unit size. In 50 years the drainage area increased from 7.7 km^2 to 23.3 km^2. The result in 1983 was the old unit operating at 95% load factor with plenty of spill throughout the year. The larger unit reduces spill and will produce on average an additional 3.3 million kWh annually.

In any redevelopment it is essential to review all aspects of the design to ensure the best use is made of the potential available as over the years many design parameters change.

With the larger unit at Topsail the discharge is twice that of the older unit while the increase in penstock diameter is only 150 mm, from 914 mm to 1070 mm. Therefore, we have much higher velocities and water hammer effects become more critical. Topsail did not have a surge tank but was equipped with a relief valve. The new unit was likewise equipped with a relief valve.

The new relief valve design, however, did not accurately model the hydraulic system. Therefore the design did not work resulting in damage to the penstock and several months of redesign and downtime.

The problem with the design was a technical one. However, the real lesson learned was the need for the owner to be familiar with the parameters used to design the equipment. Each site has its peculiarities which only those familiar with the site will know. A supplier thousands of kilometers away will not know all of the details and mistakes are very likely to occur.

It is essential that all work be checked thoroughly. Fitting a turbine into a 50 year old system is no place for blind faith. The costs in downtime could be enormous.

When retrofitting, compromises have to be made. At Topsail investigations indicated that an impulse unit was preferred. However, due to powerhouse size and space restrictions the original horizontal francis unit was replaced with a new horizontal francis unit. The savings by going to an impulse unit did not justify reconstruction of the powerhouse.

Environmental regulations also change in fifty years. A major concern which arose at Topsail was disposal of the creosoted woodstave penstock. Even after 50 years, the wood was in excellent condition and therefore in great demand by local residents for wharfs, bridges, etc. However, disposal of treated material is a very delicate environmental issue and giving material away for inappropriate uses can lead to dispute and a problem with regulatory bodies. It is well worth the time to work closely with the appropriate authorities to ensure the materials removed in rehabilitation are disposed of correctly.

At Topsail, we did allow the contractor to dump material in areas requested by local individuals for the individuals private use. Some of the material was not used in an appropriate manner and some of the material was left unused for several months. This prompted the Provincial Department of Environment to look into the situation. Although no action has been taken to date, a major problem could have resulted. Since that time, we ensure that disposal procedures are approved before any work begins.

As an example, when the 1200 mm diameter pipeline was replaced at West Brook in 1987, all details with respect to disposal were worked out with the Department of Environment. When approval to proceed was requested from the local municipal government they requested taking the wood to their depot to be used as fuel in their building heating furnace. We refused unless specifically authorized by the Department of Environment. When the town did not get approval, we proceeded to dispose of the wood as approved.

III. LAWN PLANT

Lawn, located on the Burin Peninsula on the south coast of the province, was commissioned in 1930. The powerhouse contained two horizontal francis turbine generators operating under a head of 25 m and a flow of 1 m^3/s each. Two Voith turbines were each rated at 250 hp and two Westinghouse generators were rated at 150 kw each. Water was supplied to the powerhouse through a 285 m long 914 mm diameter woodstave penstock.

Rehabilitation of this development included replacement in 1981 of the woodstave pipeline with another 1070 mm diameter woodstave pipe, replacement of the two 250 hp units with a single 650 kw unit in 1983, extension of the spillway and repairs to the forebay dam.

The penstock was replaced the same year as the Topsail penstock, and as at Topsail, development around the site was a problem. Houses were constructed immediately adjacent to the pipeline and one home even tapped into the pipe and used it for a domestic water supply. Again this resulted in construction problems, delays and compromises. In most cases the only land available is the land the pipe is on making rerouting impossible. Whatever penstock material is used usually must fit into the narrow right-of-way available.

A major concern at Lawn resulted from the increase in plant discharge. The two previous units discharged 1 m^3/s of water each. The new unit has a flow of 4.1 m^3/s. The net head calculated for the new unit was 19.8 m but the measured net head was approximately 16.7 m.

Much time was spent trying to determine the reason for this additional head loss, whether it was in the turbine or in the water transmission system. Indications are that the problem lies in the intake. Even though the flow is doubled and a larger penstock constructed, the intake was not altered mainly because of the high costs involved.

It is estimated that the velocity at the trash racks if they are 100% clean is 1.4 m/s, more than double that recommended at 0.60 m/s. This not only results in additional head loss but problems associated with debris continually accumulating on the trash racks. A small forebay with high velocities accentuates this problem with debris.

No solution to this headloss problem is available without tremendous costs. The existing forebay structure is a rockfilled dam overlaid with concrete upstream and downstream, and 10 m deep at the base. To rebuild the intake would involve nearly complete demolition of the structure. Consideration was given to erecting a bell-mouth intake upstream of the dam but calculations indicated this would only reduce losses a small amount.

This example demonstrates clearly the need for rehabilitation to match the existing systems.

Public perceptions have to be considered especially with respect to spillways and flood flows. As far as the public is concerned a larger spillway will mean larger floods and more damage. They do not realize that the flood will occur anyway and that the structure is determined by the flood not the flood determined by the structure.

At Lawn an analysis of the forebay spillway showed it could not safely pass the design flood, and work proceeded to widen the spillway which is located in a rock cut. At the time the work was ongoing, a record rainfall occurred resulting in the largest spill in many years, and some minor damage downstream of the spillway. It was difficult to convince local municipal authorities that the larger spillway had no bearing on the flood and was not directly responsible for downstream damage.

The need to redesign this spillway also shows how flood parameters and methods of analysis can change over the years and result in completely different design flood flows. This spillway which was designed and built in 1931 had to be doubled in length in 1981 in accordance with design procedures at that time. Now, in 1988, new methods of calculations and new design parameters which have come into effect in Newfoundland in the last few years indicate that the spillway again does not have sufficient capacity to pass the design flood.

Structures, such as the one at Lawn, can function adequately without spillway redesign for many years. However, rehabilitation work and the need to obtain necessary approvals could result in discovering that structures have to be redesigned to withstand much larger flood flows at high unexpected costs.

Upgrading at both Topsail and Lawn resulted in major concrete work in the powerhouse to accommodate the new units. Concrete was poured in two stages, the second stage to embed the units.

Normally this has been done using non-shrink grouts. However, at Topsail and Lawn this work was done by adding a super-plasterizer to a 25 MPa concrete mix.

A super-plasterizer improves the workability of the mix allowing it to penetrate in and around the unit components. It also gives the mix expansive properties preventing shrinkage of the concrete away from the embedded parts. In both cases workability was improved. However, the formwork did not enclose the top portions of the concrete slab resulting in expansion in that direction. The final result was a low density concrete with a compressive strength of less that 50% of that specified.

It is felt that a super-plasterizer will work in this application. However, care must be taken to ensure expansion is contained and product instructions are followed exactly.

Even though the units removed from Lawn and also Topsail and Lookout Brook were as much as fifty years old, they were well maintained and in good operating condition. It was decided that these units would, therefore, be made available for sale.

To date the Lawn Unit is the only one to be sold, to Productos Lacteos Parma of Guatemala. The Topsail Unit and the Lookout Brook Units are still available.

IV. RATTLING BROOK PLANT

This development, located in the Central region of the province, was commissioned in 1958. The powerhouse contains two units rated at 6375 kw each under an operating head of 95 m. Water is delivered to the unit by 700 m of 2.28 m diameter woodstave pipeline, 1005 m of 2.13 m diameter woodstave pipeline and about 122 m of 2.13 m diameter steel pipeline. The system is equipped with a surge tank.

Work at this site included intensive investigations to replace the existing pipe system and to replace the runners with modern, more efficient units. The runners were replaced in 1986 and 1987. The penstock has not been replaced to date.

This project can be used to illustrate two points; 1) how operating characteristics can change over the years and the effects it can have on plant operation and production, and 2) the extent unforeseen items can influence a project schedule and cost.

When Rattling Brook was built in 1958, it was a "stand-alone" system serving a particular region and it was the only source of electrical energy for that region. Two units were therefore installed, one unit as a back-up to the other. As such, the penstock was sized for one unit only in operation at any given time.

In 1966, however, with the completion of the provincial transmission grid and an ever increasing use of electricity, it became advantageous for Newfoundland Light & Power to operate both units especially during periods of high inflows. However, even though the units have a combined capacity of nearly 15 mw, due to penstock restrictions, a maximum load of only 10.8 mw could be obtained.

Rehabilitation of this system would have to include erection of a larger diameter penstock. This was investigated in 1983 but replacement of the pipeline at that time could not be shown to be economical.

Replacement of the runners was shown, however, to be economical and in 1984 two modern runners were ordered to replace those existing. The economics of the project were based upon a 3 to 4 percent increase in efficiencies. Due to delays in obtaining the runners from the manufacturer, the first runner was not replaced until 1986 with the second runner replaced in 1987.

In erecting the runners several problems were encountered with fitting them into the old units. One of the units when erected in 1958 experienced a vibration problem which until 1986 was not remedied. The unit operated for nearly 30 years with compressed air pressurizing the scroll case to reduce vibrations to a tolerable level. This type of problem along with having to ship the shaft away for machining resulted in a much longer project than anticipated and much higher costs.

In this project, as well as two other sites we have rehabilitated by replacing mechanical components only, the time to actually do the work was much longer than anticipated or scheduled and longer than would be needed to erect a new unit package. This has to be kept in mind when estimating and scheduling a rehabilitation project.

It was previously noted that the economics of the Rattling Brook Rehabilitation Project was based upon a 3 to 4% increase in efficiency. The only method available to test if this increase was actually attained is through an Index Test, which has an accuracy of ± 1% to ± 2%. The problem is therefore obvious when a test which has an accuracy ± 2% is used to verify an expected 4% increase in efficiency.

However, the cost of other methods available to test efficiencies cannot be justified on small projects such as Rattling Brook.

Index Tests were conducted, however, before and after the rehabilitation. The results indicated that the realized additional production did justify the cost of the project.

V. MORRIS DEVELOPMENT

The Morris Plant is a new development located in the watershed of the existing Mobile Hydro Development on the Southern Shore of the Avalon Peninsula, about 40 km from St. John's. The plant has a capacity of 1050 kw operating under a head of 28.5 m and a flow of 4.3 m^3/s.

Preliminary work on the project began in 1981 with re-evaluation of a project originally investigated in 1950 and an investigation of Fisheries and Environmental concerns.

This development was a combination of rehabilitation and new construction. An existing canal once used to divert water to an adjacent watershed was regraded and used as a power canal. An existing reservoir at Mobile Big Pond was used as the main water supply and the existing spillway served as the spillway for the new development. A forebay/intake was constructed in the canal, a powerhouse constructed on the shores of Mobile First Pond and a 200 m long, 1.67 m diameter fibreglass penstock used to connect the two.

One of the reasons the decision was made to proceed with this plant was its minimum environmental impact. However, diversion of the flow into a canal affected a section of fish spawning gravels which had to be replaced. It was decided to use the flow from the plant to develop a spawning area in the tailrace. Working closely with the Department of Fisheries and Oceans (DFO), a layout was designed which identified design parameters to ensure the lost Quananiche (land locked salmon) spawning grounds were replaced.

This spawning ground was constructed with the plant and remains in operation. The area is being used by a large number of fish including Quananiche and Eastern Brook Trout.

Our experience with the spawning canal has revealed some of the following concerns. The spawning gravels were placed to suit the Quananiche population. It appears the gravels are not suited however to Eastern Brook Trout which is a smaller species. The velocities in the tailrace appear too high for the smaller fish. Department of Fisheries and Oceans have requested that boulders be placed in the stream to create quiet areas for the smaller fish.

Our major concern is that DFO is requesting Newfoundland Light & Power Co. Limited to have changes made to the original design at NL&P expense. Even though we want to see the design work properly, we do not want to get caught with additional expenses outside that originally agreed to. The design parameters and designs were completed in conjunction with DFO and the system constructed at a cost to NL&P of about $100,000 or about 4% of the project cost.

We do not feel that any developer should be burdened with unforeseen costs once a project has been approved and mitigative measures agreed to and put in place. All conditions of approval should be known up front.

At Morris we erected our first fibreglass penstock, which to date has posed no operating problems and has been maintenance free. The major advantage of fibreglass over woodstave is the ability for operators to be able to dewater when necessary without being concerned about subsequent leakage. A disadvantage with woodstave, especially older poorly designed pipelines, is the extensive leakage which can occur after dewatering. This problem is not as critical in newer woodstave pipes where there is sufficient spring-line support.

When working with drawings or designs which are very old one has to be careful with the use and transfer of datums. At Morris we were working with two different structures Mobile Big Pond and Mobile First Pond, both on the same system but both constructed at different times using a different datum.

The discrepancy was noted in sufficient time to prevent any problems. However, if it had not been noted our powerhouse floor would have been submerged when Mobile First Pond was spilling. It is imperative that all existing data be verified.

Morris is the only plant built by Newfoundland Light & Power Co. Limited since 1960 and is built solely as an energy plant. The economics of the project is based upon a 1 MW unit running at a 98 percent loadfactor and feeding into the forebay of the downstream 10 MW Mobie Plant. The reasons Morris was built over other sites were that it allowed for more efficient use of the watershed, using the water twice; it was within a Newfoundland Light and Power Watershed thereby it does not come under legislation limiting developments on crown land and most importantly from an economic feasibility point of view, some of the main civil works were existing.

New work at Morris consisted mainly of an intake, penstock, powerhouse and tailrace. Major upstream structures required little or no work, the main reason the project was able to proceed.

VI. FUTURE POTENTIAL

Newfoundland is a province blessed with an abundance of water and physically there are many sites available to the small hydroelectric developer.

Presently in Newfoundland about 31 small sites are developed. Newfoundland and Labrador Hydro operates four sites, Newfoundland Light & Power operates 22 sites each of which is less than 15 MW, Abitibi-Price operates 2 sites in Central Newfoundland, Corner Brook Pulp and Paper operates one site at Deer Lake and there is one small development at Mary's Harbour in Labrador.

Inventories have been compiled by several organizations over the years to actually determine the number of potential sites available and their relative feasibility. In 1983 a Newfoundland Light & Power inventory study identified 121 sites on the island portion of the province near the areas serviced by that company. Many of these sites have been visited in the field and preliminary feasibility studies completed. A 1986 report by a local engineering company identified 160 sites, all of which generally run from 1 MW to 15 MW in size. Little or no work has been done on sites less than 1 MW. The possibilities in this range must be endless.

From a Newfoundland Light & Power viewpoint, for any project to be considered economically feasible the value of the energy produced over the life of the facility must be greater than the cost to construct and operate. We buy most of our energy from Newfoundland and Labrador Hydro at a blended cost of hydroelectric energy and energy from oil fired units. Therefore, the energy rates we use in our analysis to determine feasibility are relatively low, about 4.5 ¢/kWh in 1988.

This has made many of the projects we have investigated marginally economical or not economical at all even though physically the sites are very attractive. An independent producer who possibly could base his economics on reducing oil fired production by Newfoundland and Labrador Hydro may very well show these sites to be economical.

A very important tool to Newfoundland Light & Power in our rehabilitation work and our investigations for new sites is the use of Class 34, Accelerated Capital Cost Allowance. Under this Federal Program money spent on energy projects such as small hydro under 15 MW can be written off in three years at a rate of 25%, 50%, 25%. This program alone has allowed us to spend over $20 million over the past 8 to 10 years upgrading our facilities. Much of this work probably would not have been economical without the availability of Class 34. And without Class 34 it will be very difficult for us to justify further development using the economic parameters utilized to date. Our experience has shown that Class 34 is a powerful tool in promoting small hydro. For example on a $3,000,000 project the estimated savings which can be attributed to the use of Class 34 can amount to as much as $1,200,000.00.

Probably the biggest drawback to development of small hydro in Newfoundland is legislation which gives Newfoundland and Labrador Hydro (Hydro), a Crown Corporation, the right to develop all sites over 1 mw on crown lands. This means of course all proposed developments over 1 MW would have to be approved by Hydro. To date no sites have been approved.

It is our opinion that the use of private sector money to develop small hydroelectric facilites in Newfoundland should be promoted. Such a policy would increase construction activity, reduce the dependency on oil fired units and not cost the government a cent. If this policy is not forthcoming than developers have to look at areas other than crown lands where Hydro does not have jurisdiction. Such areas would include land controlled by pulp and paper companies, private property or for Newfoundland Light & Power, sites within our existing watersheds.

In Newfoundland there is an Environmental Assessment Act and all sites over 1 MW must be registered under that act for Environmental Assessment. The assessment is directed by a committee of regulating bodies such as Energy, Environment, Fisheries, Wildlife, etc. Depending upon the project, assessment could range from a Preview Report to a full set of public hearings.

It has always been our opinion that small hydro does not demand the same treatment environmentally that the large project demands. A run-of-river plant with minimum impoundment, consisting of one dam does not have the environmental impact that a 50 MW project consisting of several dams, flooding and diversions would have. We have always maintained that a simplier procedure should be put in place for smaller projects say under 15 MW, to tie to the Class 34 program.

The lack of population is also a draw back to development of many of the sites in Newfoundland. Many attractive small sites are located in remote areas away from the populated regions. The subsequent requirement for long access roads and transmission lines make the sites uneconomical.

There is no doubt that physically there is an abundance of small hydroelectric sites in Newfoundland. However, not enough emphysis is placed on the industry by the provincial government and their agencies. They should be encouraging development in small hydro by making the environmental process more steamlined for small projects, making more crown land sites available to the developer, and through their crown corporation, Newfoundland and Labrador Hydro have a definite policy on the purchase of energy produced. Small hydro is a proven technology, environmentally attractive and will benefit the people of the province of Newfoundland.

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Experience and Measurements on Small Hydro Turbines

By
H. Netsch, M. Yves Jean

1

1. EXPERIENCE AND MEASUREMENTS ON SMALL HYDRO TURBINES

PROF.DR.H.NETSCH,ING. UNIVERSITE LAVAL and YVES JEAN,FANNY INDUSTRIES

1.1 Introduction

Small hydro electric turbines and stations are not simply scaled down versions of large sized plants. Whereas optimization parameters dicatate the size and operating conditions of large sized turbines, these parameters generally cannot be applied to the development of small power units. Modern materials such as plastics have influenced turbine construction. Advances in electronic components and circuits have resulted in the development of highly sensitive turbine speed sensors, replacing the older flyball tachometers.
The development of small hydraulic sets requires sound theoretical knowledge and also industrial development and testing experience.
We will present our experience on small power turbines, and in particular a unit which has been operating successfully for several years at a remote off the grid site (Fig.1.1.3 and I.I.5) with a minimum of maintenance. Extensive measurements haved been carried out on the system and some of the results are presented in section 1.6.4 .

1.1.1 Research and development work at Université Laval

At Université Laval we have several turbines in the Hydraulic laboratory, including Pelton, Kaplan and Axial Flow machines. It is even possible with the Pelton turbine to simulate Francis units of varying specific speeds n_q. The Axial Flow turbine was calculated, designed and then fabricated in the workshop of the Mechanical Engineering Department. All the turbines are completely instrumented . The electronic governors and the electrical systems were deveopled and built in the Electrical Engineering Department. Details of these machines are shown in Figures I.I.I and I.I.2. All photographs will follow the text.

1.1.2 Research turbine located in a forest at LaTuque, 250km north of Québec.

Another fully instrumented tubular axial flow research turbine provides electricity under off-grid conditions to a small site, 25o km to the north of Québec. This unit generates approximately 15 kW , but with higher heads and blade optimization, considerably more power could be generated. Once again, the turbine and the complete electronic and electrical system were developed and built at Université Laval. This unit has been in operation for 6 years with minimal maintenance provided by unskilled local labour, and presenting very few problems of either a mechanical or electrical nature (cf. reference in Fig. 1.6.5). The development of this unit was made possible due to the financial support of the Québec Ministry of Energy, Mines and Ressources. This small hydro electric allowe us to carry out a program of detailed measurements as well as gaining long term operational experience. Details of this machine can be seen in Figs.I.1.3 to I.1.5.

1.2 Present developments

1.2.1 The 120 kW, high head axial Flow Turbine.

The development of this load controlled set has been made possible due to a grant by the Federal Ministry of Energy, Mines and Ressources in Ottawa.

Work on the turbine has been terminated as well as the electronic control system and the electric load elements. The rotor blades will be fabricated by a numerically controlled machine at the C.E.G.E.P Levis-Lauzon under the direction of Professor Julien Morasse. This work will begin once the installation site has been determined. Negotiations for possible sites are presently underway.(Fig.1.2.1)

1.2.2 Microprocessor Control

We are also in the process of developing a microprocessor control system for small and medium power turbines again thanks to the aid of the Federal Ministry of Energy, Mines and Ressources. This control unit will be applied to turbines equiped with secondary load control. Mathematical models are being developed for both turbine and control system so that the microprocessor can provide optimal control for any possible n_q. Tests will be conducted on a specially developed motor-generation set, simulating a hydraulic turbine and on the turbines in the Hydraulic Laboratory at Université Laval and on the turbine in LaTuque.

1.3 The operation of turbines supplying a grid or consumers at a remote off-grid location.

1.3.1 Regulation and stability of turbines, feeding into a grid or operating under off-grid conditions.

Speed regulation and stability, following transient perturbations can pose severe problems for consumers at off-grid conditions. With the increase in the number of units forming a grid such situations become less difficult to master. For this reason, we will compare mass flow control and load control.

1.4 The regulation of hydro-electric turbines by water mass flow control, by load control,for variable speed machines and turbines without a governor.

1.4.1 Introduction

Any turbine governor ensures that the turbine output torque equals the load at the generator, since only then is a constant speed operation or desired speed band possible. The system is composed of the turbine, including the water masses in the penstock,the generator, the grid with various loads, such as pumps,machine tools and resistive loads, such as heaters and lights. The system and the governor form a closed loop, which is then excited by load variations. It is the task of the governor to ensure that transient rotational a speed variations and stabilized and of short duration. The stability problem can only be solved by establishing a mathematical model of the exciting load-speed relationship for the system under investigation. Experience permits certain simplifications and the apropriate selection of elements to obtain a satisfactory control sequence. Provisions must nevertheless be made to allow adjustments of the system at the station site.

1.4.2 Water mass flow control

This mode of control is mainly used for turbines of medium and high power output. The water mass flow is adapted to the load by appropriate gate or needle valve positioning. Large forces are necessary to achieve this task, introducing nonlinearities into mathematical relationships through hydraulic amplifiers and their metering valves. Although interesting, this results in considerable complications both as regards the mathematical solutions and the selection of equipment. Such turbines are expensive but do use the hydraulic potential very economically.

1.4.3 Load control

The control problem is greatly simplified by electronically switching secondary load elements in parallel with the industrial load. The turbine operates at its highest efficiency point and can be connected to a long penstock. The frequency remains constant as long as the maximum load torque is equal or inferior to the maximum turbine torque.

1.4.4 Variable speed operation

This mode is ideal for low and medium power axial flow turbines. An increase in rotational speed proportionally increases the water mass flow with little change in efficiency. It must be mentioned however, that with a speed increase the cavitation parameter S of these cavitation sensitivity units increases with the square of the speed ratio n/n_m and consequently the suction head decreases.

1.4.5 Turbines without a governor, equiped only with an emergency shut down system

These turbines are connected to a grid which controls the frequency. Their power output is generally constant, but this can be changed through the use of moveable guide vanes. The emergency shut-down system brings the unit to a standstill in case of separation from the grid. This is the most economical form of power production.

1.5 Analog and Digital control systems

1.5.1 Introduction

Irrespective of whether a turbine is connected to a grid or supplies an isolated site, a control sequence can be achieved by either analog or digital means.

1.5.2 Load control by an analog control system

We have developed analog acting regulators for turbines in the small and medium power output range. Tests and experience have shown that this mode of control is ideal for very small power generation.

I.5.3 Load control by digital control systems

At the present time, we are developing a digital control system for turbines of small and medium power generation. The generator will be operated at constant speed. The digital control system possesses the following features:

1) High accuracy due to fast sampling
2) Absence of component drift
3) modification of control parameters purely by software commands
4) Internal surveillance of a control sequence during transient operation
5) Continous surveillance
6) Optimizing the operation,providing maximum power
7) Initiation of the emergency shut down.

1.6 The merits of the water mass flow control and load control

1.6.1 Introduction

Mathematical models will be given for both systems. These indicate clearly the preference of load control for small power output.

1.6.2 Water mass flow regulation

To ensure constant speed of a hydraulic turbine requires that the energy delivered to the generator must be equal to the power required. This is achieved by the regulator which positions the guide vanes (guide and runner vanes in the case of Kaplan turbines) and adjusts the water mass flow to the load. In the following very simple and elementary example, the speed response of a turbine to a load variation will be presented. It is necessary also to discuss briefly the characteristics of all elements in the closed loop.

The sensitived analog frequency detecting device can be represented by the mechanical model, illustrated in Fig.I.6.I

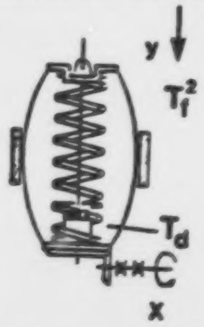


Fig.1.6.1 The frequency sensor.

Any electrical system can preferably be represented by its corresponding mechanical devices.

Its mathematical model is

$$T_f^2 y'' + T_d y' + b_b y = x \qquad (1.6\text{-}1)$$

where

T_d = characteristic time
T_f = Characteristic time of the tachymeter
b_b = $(f_{max} - f_{min})/f_{mean}$. f_{mean} is often f_{rated}
y = Y/Y_{max}, where Y is the displacement of the spool and Y_{max} it max.value
x = n/n_{mean} = f/f_{mean}

The spool valve, the servomotor and the feedback mechanism are represented by the system illustrated in Fig.I.6.2

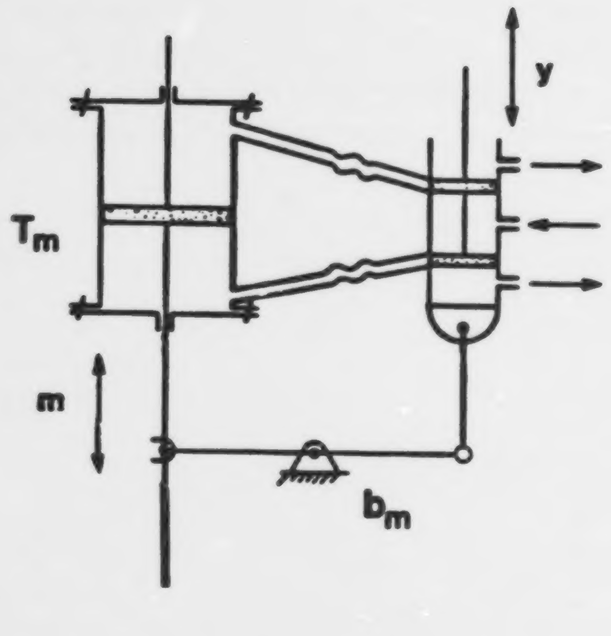


Fig.1.6.2 The spool valve, the servomotor and the feedback lever

The mathematical model of this element is

$$T_m m' + b_m m = y \qquad (1.6\text{-}2)$$

where

T_m = gate (needle valve) servomotor closing time
b_m = gain of feedback system (adjustable)
m = M/M_{max} where M is the piston displacement and M_{max} its maximum value.

Transient operation.

During a transient operation, a torque $(\Delta C_T - \Delta C_Z)$ accelerates the turbine, according to

$$(\Delta C_T - \Delta C_Z) = = (2\ p /60)\ J\ d\,(\Delta n /dt) \qquad (1.6\text{-}3)$$

where J is the moment of inertia and ΔC characterizes the torque.

For very short pressure lines, the Equ.(1.6-3) leads to

$$T_a\, x' + e_N\, x = z - e_s m \qquad (1.6\text{-}4)$$

the mathematical model of the rotating system and the load,

where

T_a = start up time of the rotating system: $T_a = (2\ p /60)\ n_m / C_{Tmax}$

e_N = $e_T + e_Z$ self regulation parameter of the system

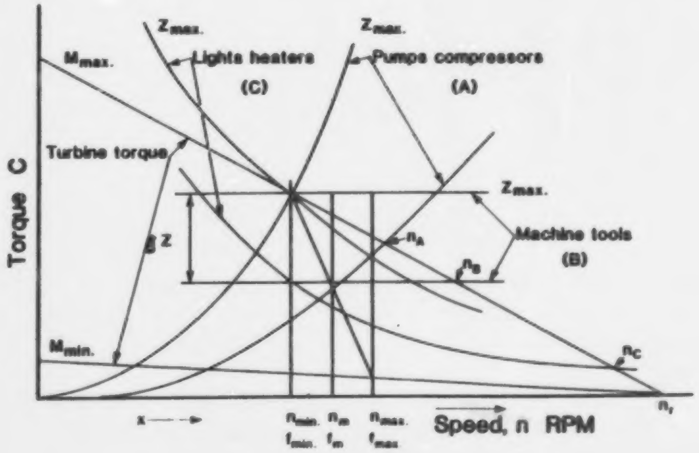
e_T = self regulation parameter of the turbine dependent on the torque vs. speed characteristics. $e_T = (n_r - n_m)/n_m$

e_Z = self regulation parameter of the load $e_Z = 2$ for centrifugal pumps or blowers, $e_Z = 1$ for machine tools, $e_Z = -1$ for Ohme load (heaters, lights). $Z = (n/n_m)^S Z_{max}$

e_S = relating a specific gate position to a specific power output

z = Z/Z_{max}, Z = variation of the load torque, Z_{max} ist max.value for $n = n_m$

These relations are outlined in Fig.1.6.3.



load variation Δ Z
unchanged guide vane position m
final steady speeds:
n_A pumps, n_B machine tools
n_C Ohm loads (lights)

Fig.1.6.3 Torque-speed relationship for the turbine at various loads.

From Fig. 1.6.3 it follows that $n_A < n_B < n_C$. This demonstrates that a governor for resistive load demands must act very quickly to a load change to assure stability. This is particularly important if the turbine operates only at a fraction of its rated load.

When neglecting the influence of the water masses in the penstock, we obtain the speed-load relationship for the simplified overall control system of a Francis Turbine, illustrated in Fig. 1.6.4:

$$T_aT_f^2T_m m^{(iv)} + [\,T_f^2(T_m + T_ab_m) + T_aT_dT_m]\,x''' + [T_d(T_ab_m + T_me_N) +$$

$$T_aT_mb_b + T_f^2b_me_N]\,x'' + [T_db_me_N + T_mb_bb_m]\,x' + (e_S + b_bb_me_N)\,x =$$

$$T_f^2T_mz''' + (T_f^2b_m + T_dT_m)\,z'' + (T_db_m + T_mb_b)\,z' + b_bb_mz \qquad (1.6\text{-}5)$$

In the case of a very sensitive governor, T_f tends to zero and the previous equations simplifies considerably :

$$T_aT_dT_mx'''+[T_d(T_ab_m+T_me_N)+T_aT_mb_b]x''+(T_db_me_N+T_mb_bb_m)x'+$$

$$(e_S+b_bb_me_N)x = T_dT_mz''+ (T_d\,b_m+ T_mb_b)z' + b_bb_mz \qquad (1.6\text{-}6)$$

or with $T_d = 0$,

$$T_aT_mb_bx'' + T_mb_be_Nx' + (e_S + b_bb_me_N)\,x = T_mb_bz' + b_bb_mz \qquad (1.6\text{-}7)$$

For steady state speed or frequency devitation,resulting from a load variation z , x is in all cases

$$x = \frac{b_bb_m}{e_S + b_bb_me_N}\,z \qquad (1.6\text{-}8)$$

For z = 1, x becomes the frequency band or speed droop, varying, as e_N indicates with the load and turbine parameters and can also be modified by altering the value of b_m, the gain of the return element.

Furthermore, the value of the gain b_m allows also a precise load distribution between two turbines, operating in parallel.

As can be concluded from an inspection of Fig.1.6.3 a resistive type load requires a vigourously acting governor to reduce the water mass flow. However, a fast acting governor, when displacing guide vanes, induces pressure surges and thus destabilizes the control sequence.

This unfavorable situation can be somewhat eased by installing a large fly-wheel.

1.6.3 Load Control

The total load connected to an off-grid turbine remains constant and is composed of a primary component and a secondary, frequency regulating part.

The turbine has fixed vanes and can be manufactured economically. It operates in a small area around its best efficiency . Its size depends on the switching speed of the secondary load. For the unit we have developed, it is more appropriate to speak of the best efficiency point and not of an area. Destabilizing dynamic pressure variations in the penstock do not exist. The character of the load is relatively unimportant and resistive loads pose no problem whatsoever. The switching sequence can be provided by either an analog or digital regulator.

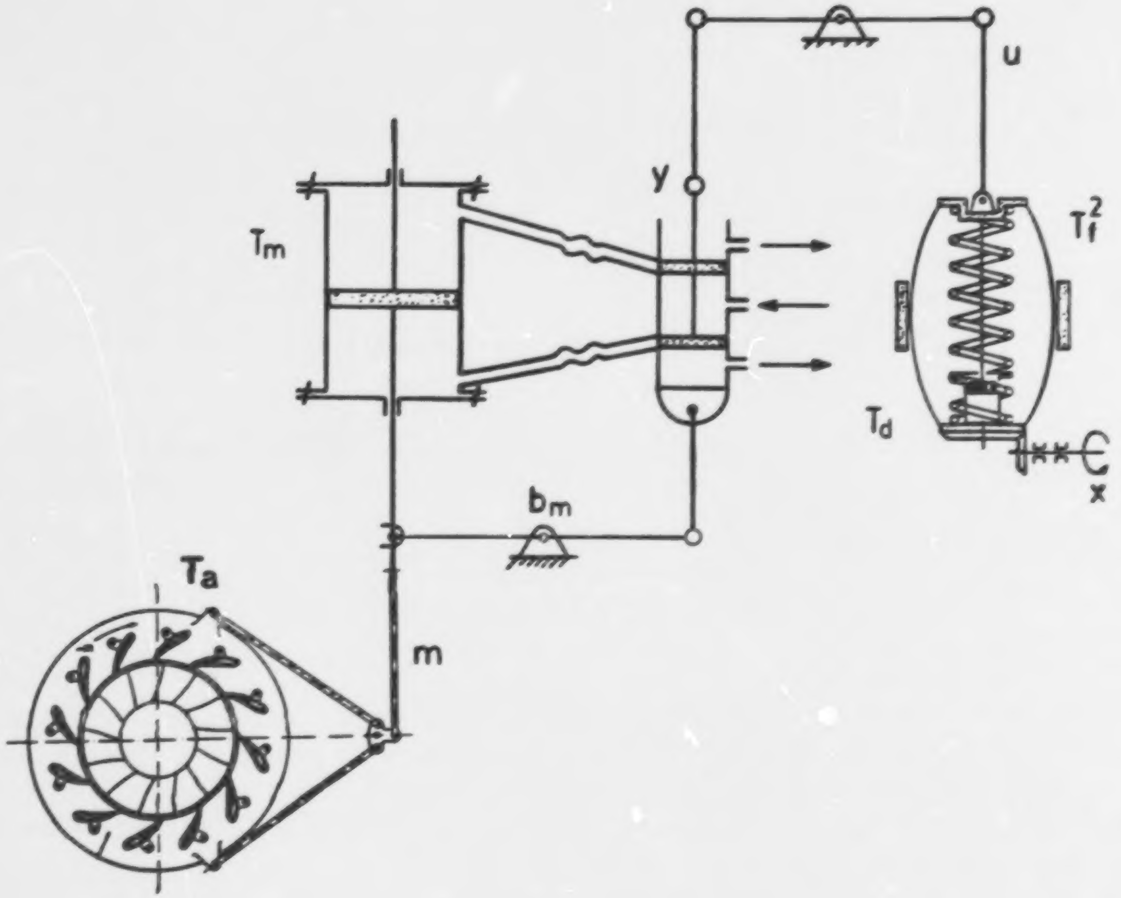


Fig.1.6.4 Schema of a Francis turbine with a proportional "P" governor.

1.6.4 Experience with small hydro turbines

Turbines above a certain power level must be equiped for reasons of water economy with a mass flow regulator. Several units operate then in parallel and form a grid. The presence of purely resistive load is then somewhat remote. For small units, load control is preferable. The turbines are of simple construction and stability problems do not occur, independent of the type of load, as indicated by the enclosed reference, Fig.1.6.5.

Due to the short time at our disposal to design and fabricate the LaTuque turbine, we were obliged to use an availabled water lubricated plastic radial bearing. To be on the safe side, we increased the shaft diameter to keep the specific pressure low and the radial clearance was kept larger than for metal bearings. The lubricating water in bearings can reach temperatures around the boiling point and no heat dissipation is possible with plastics.
When later changing this bearing for a metal, graphit lined one we saw traces of wear on the plastic bearing surfaces. The shaft was not affected. After years of operation with the replacement bearing, we dismantled the bearing system and measured both the shaft and bearing. We obtained the initial dimensions and saw no scratches on either the shaft or the bearing.

Closing down the turbine at the consumer end.

A separate signal transmission line was installed at the power consuming end of the installation. It is possible to stop the turbine by depressing a button. During severe thunderstorms, inductive currents and voltage on this signal transmission line provoked a closing down of the turbine. It was unpleasant to reinstall power in a rainstorm, since the distance between consumer and power plant is approximately 700 m. The situation was corrected by the installation of a relay.

The letter of reference, Fig.1.6.5 indicates clearly that no problems have arisen.

1.6.5 Measurements

a) Turbine

The turbine efficiency was measured by using small flow meters, Fig.1.6.6.The draft tube efficiency was also determinated. Vibration amplitudes of the extremely quietly operating turbine were obtained by installing accelerometers.
Pressure fluctuations between the stationary and rotative and behind the rotating vanes were measured. In addition the three dimensional flow field between and behind the vanes (blades) was found by using a directional probe, Fig.1.6.7.

b) Electrical system

Detailed tests were made on the governor, the voltage regulator and the security system. The Figures 1.6.8 to Fig. I.6.11 illustrate some of the results.

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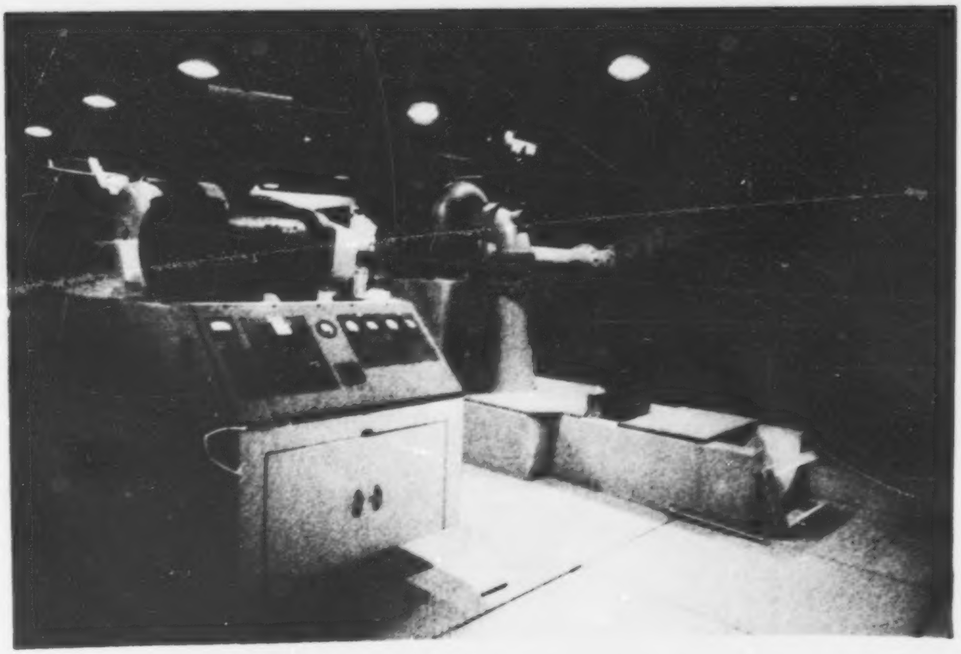


Fig.1.1.1 Cooperation University - Industry. Partial view of the hydraulic machinery laboratory University Laval.

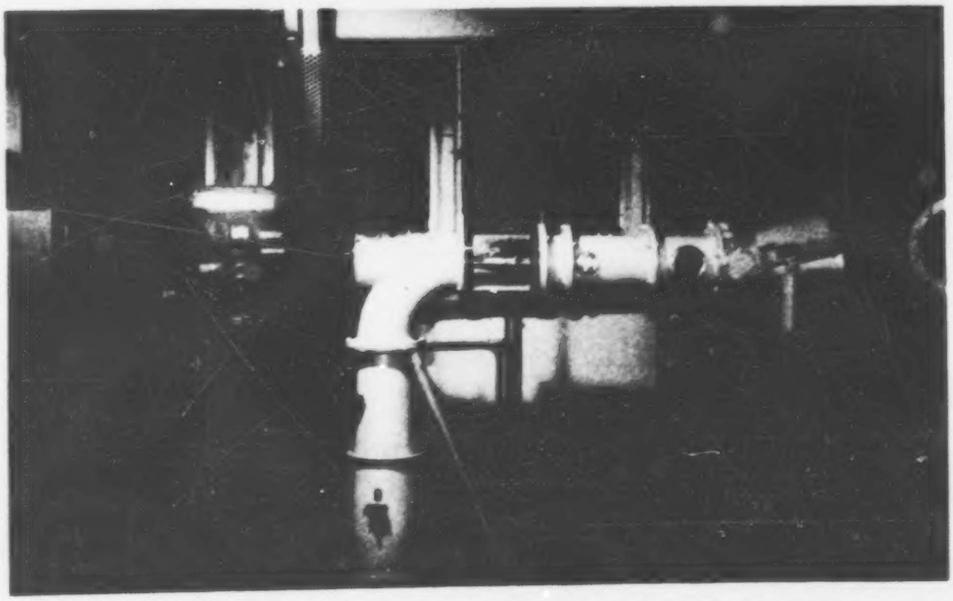


Fig.1.1.2 Cooperation University - Industry. Tubular turbine of 11 kW Variable parameters: Head range $H_{max} = 8m$, suction head, velocity.
Turbine fabricated in the Mechanical Engineering Department

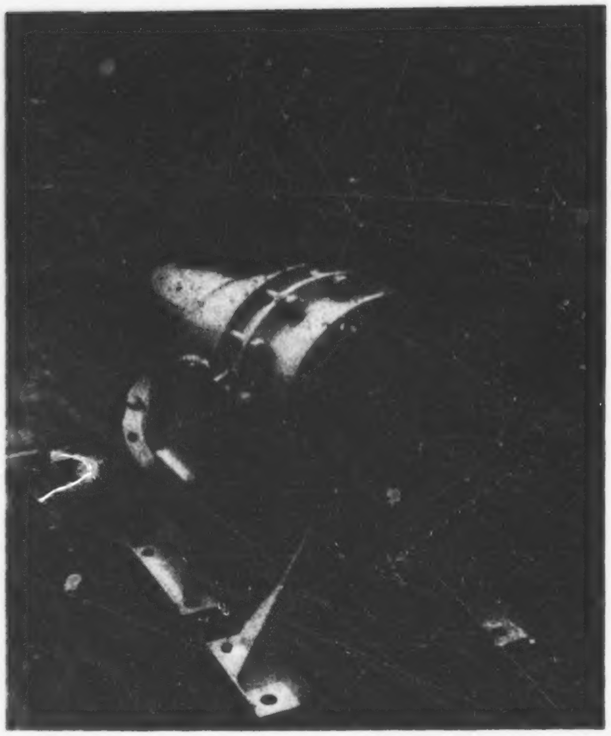


Fig.1.1.3 Hydro electric power plant LaTuque. Tubular turbine, Alternator and Butterfly valve. H=6.2m, n=1200 r.p.m. N=15 kW.Possibility to increase the power for higher heads, using the same shell. Turbine fabricated in the Mechanical Engineering Department.

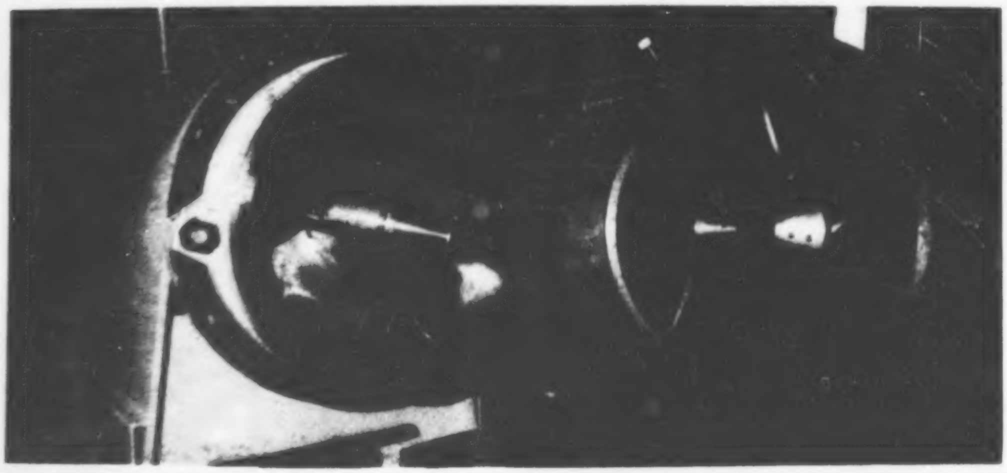


Fig.1.1.4 Hydro electric power plant LaTuque. Stationary guide vanes and runner blades.

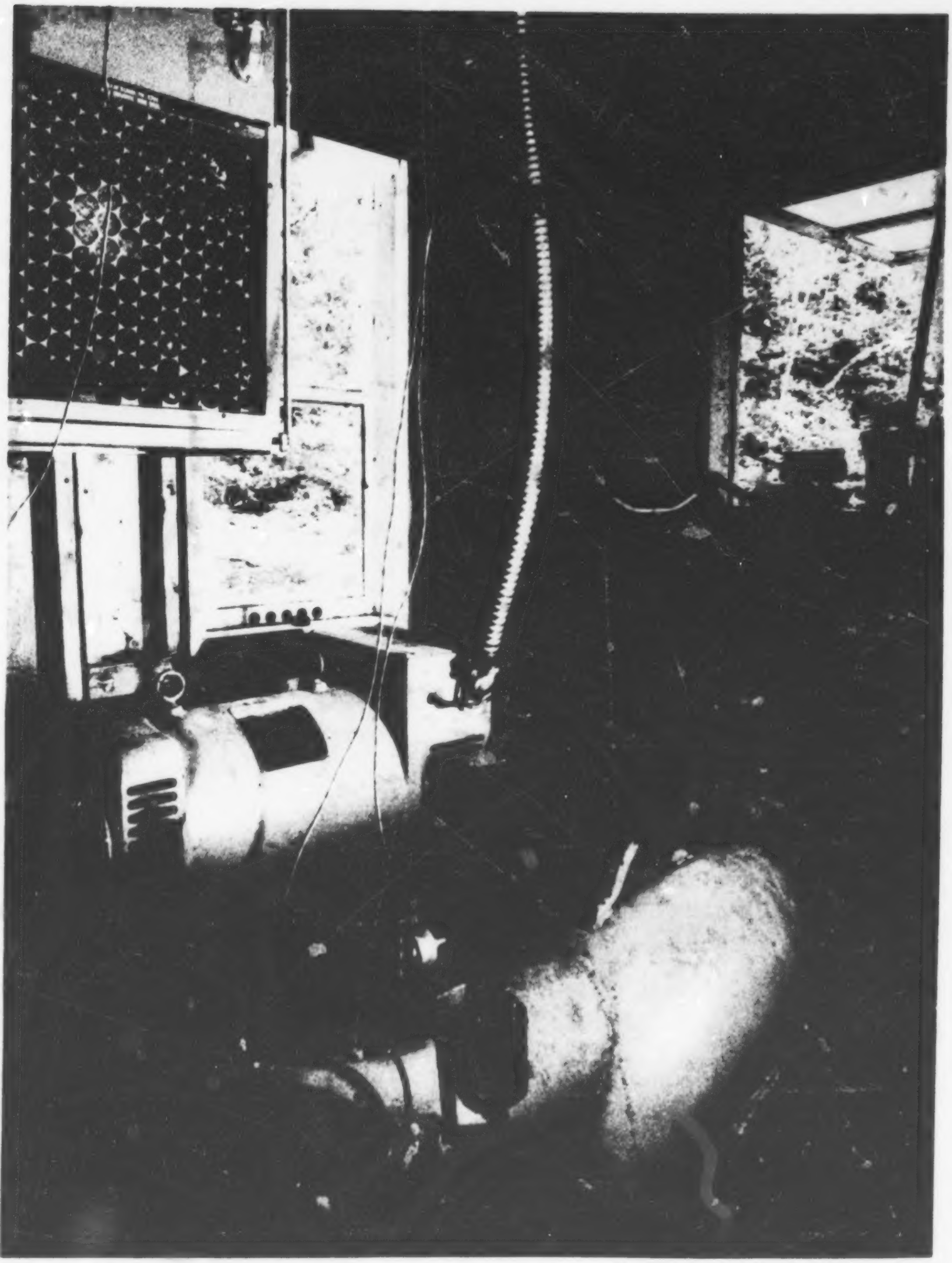


Fig.1.1.5 Hydro electric power plant LaTuque. Turbine and secondary load elements.

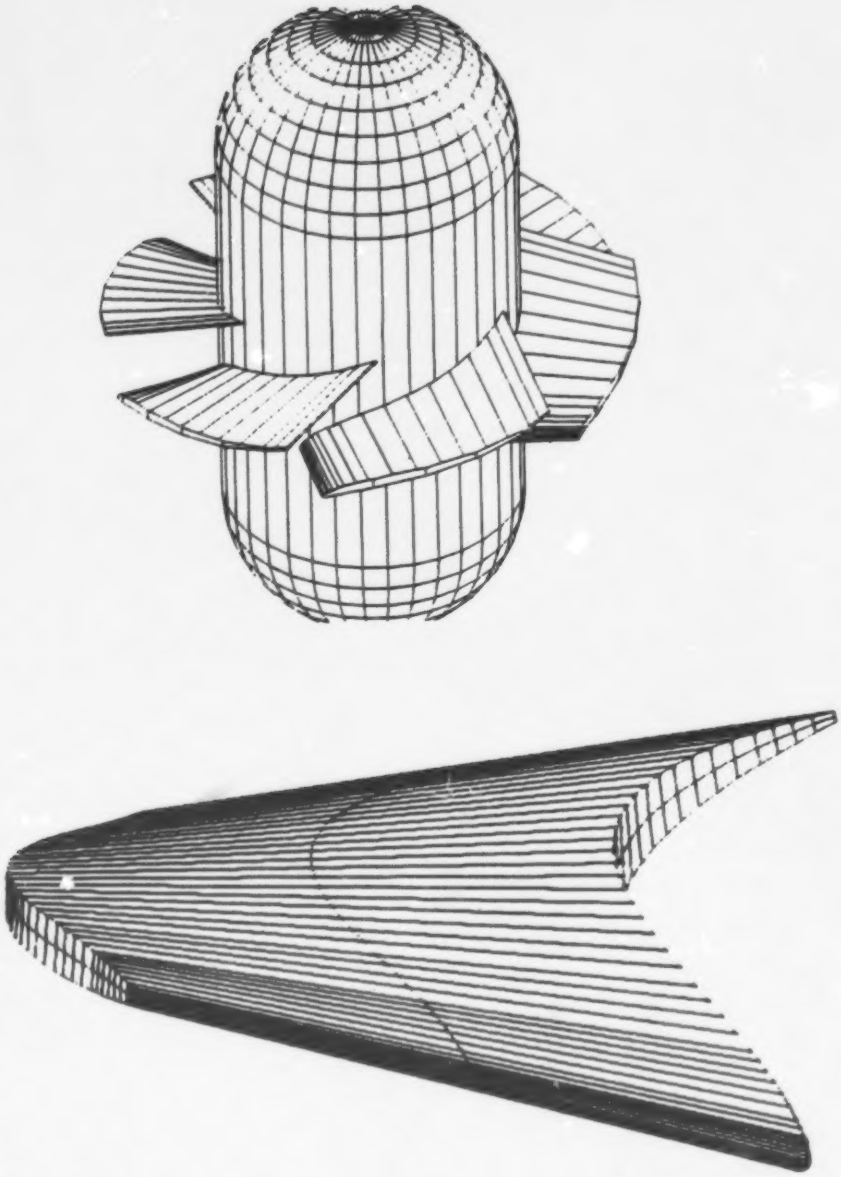


Fig.1.2.1

Computer assisted design and fabrication of the turbine rotor blades

Prof.J.M orasse

Translation of a letter from
M.Emile Lefort

Shawinigan, July 8th,1985

M.Herbert Netsch
Mechanical Engineering Department
Université Laval
Québec.

Just a few words to present our deep gratitude to you, to M. Viarouge and Yves Jean and to the personnel of the Mechanical Engineering Department of the University for the design, manufacture and the excellent performance of our turbine , installed in summer 1981 . To date, we have had no mechanical or electrical problem.

All the members of the Club des Alcaniciens and myself are very grateful to you and the personnel of your group for this effort , knowing how much of your valuable time you have given to us to improve the efficiency of this turbine.

The spare parts , that you have given to us are much appreciated . This proves once more that even after four years , or in other words , since the installation of the turbine , you have continued to give your attention to the operation of this turbine .

Once more : THANK YOU VERY MUCH ....

Yours sincerely

Emile Lefort
2654 rue St.Marc
Shawinigan, Québec

Fig.1.6.5 Hydro electric power plant LaTuque. Reference.

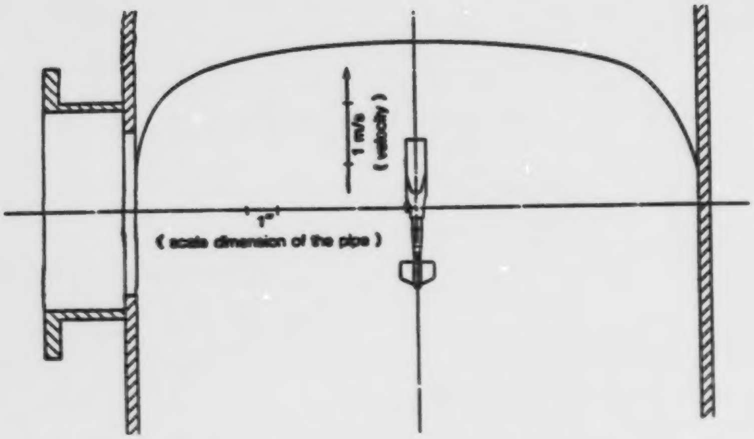

1 m/s
(velocity)
1"
(scale dimension of the pipe)

Fig. 1.6.6 Efficiency tests

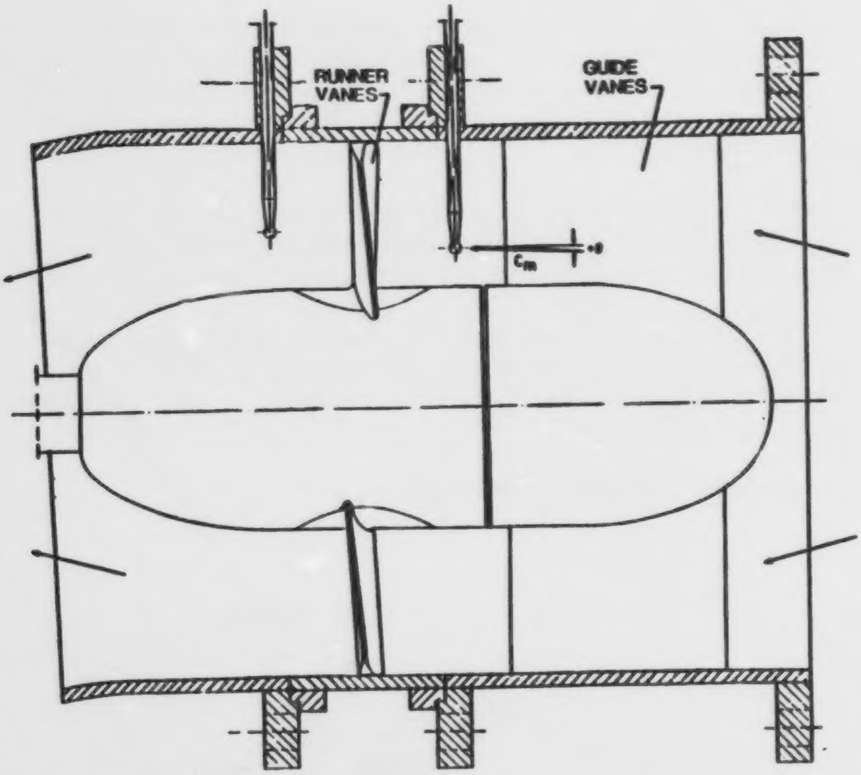

RUNNER
VANES
GUIDE
VANES
c_m

Fig. 1.6.7 determination of the three-dimensional velocity field behind the blades

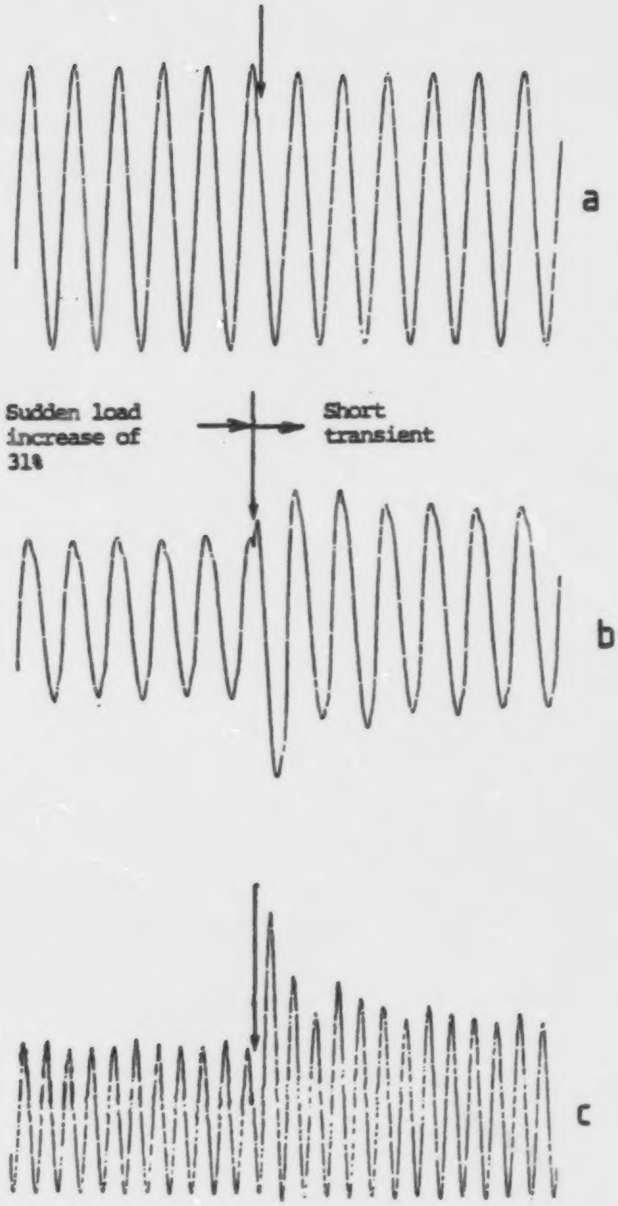


Fig.1.6.8 Sudden increase in load equal to 31% of the rated turbine power.

a) Alternator voltage V (t)
b) Alternator current I (t)
c) Generator Power V(t) I(t)

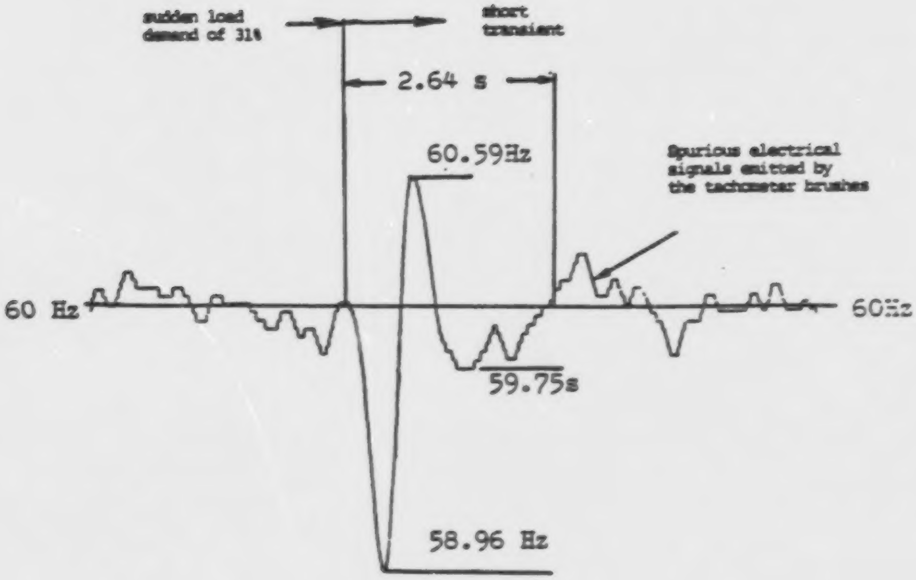
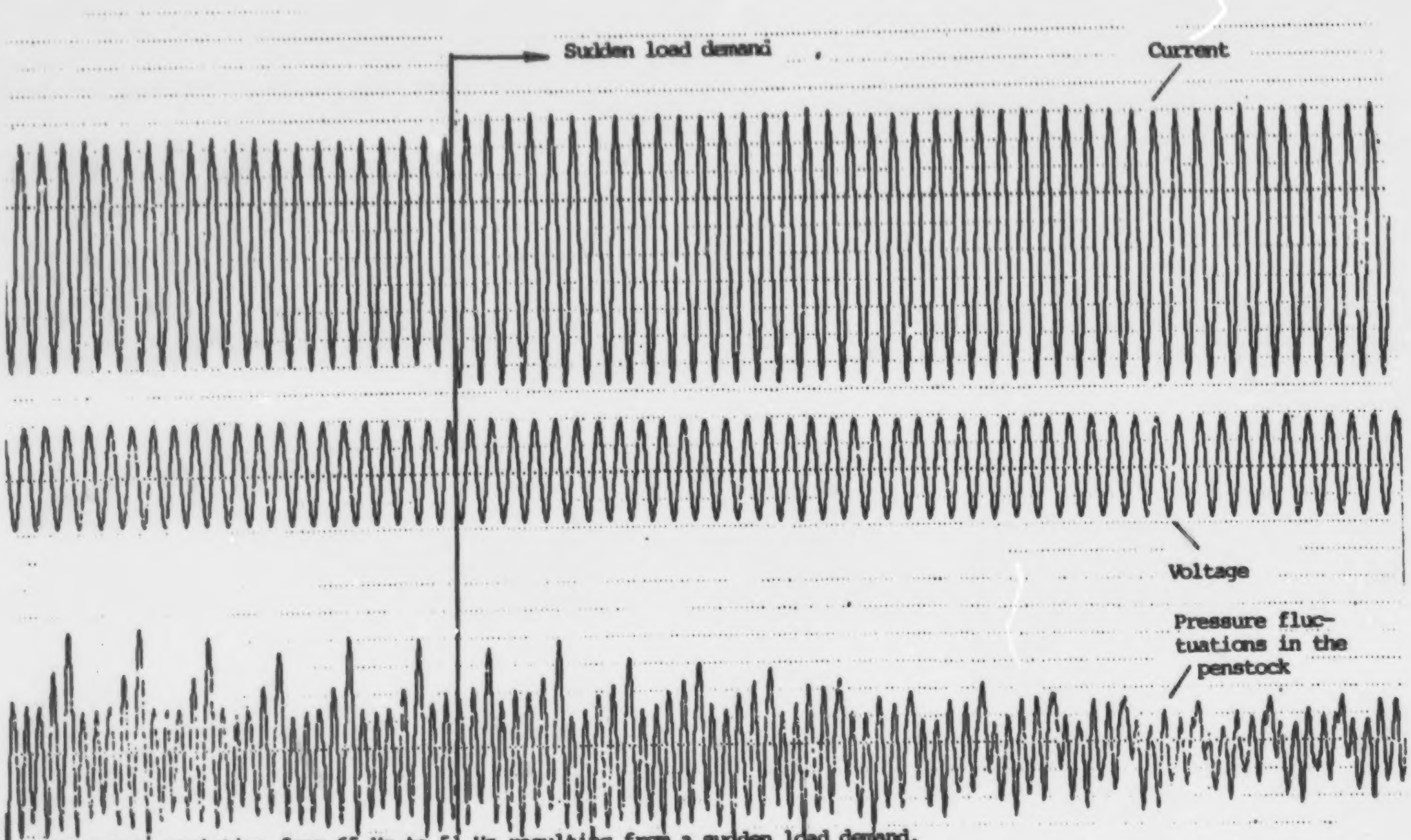


Fig. 1.6.9 Sudden increase in load equal
to 31% of the rated turbine power

Transient frequencies

Both Voltage regulator 240 V and
Frequency regulator 60 Hz active

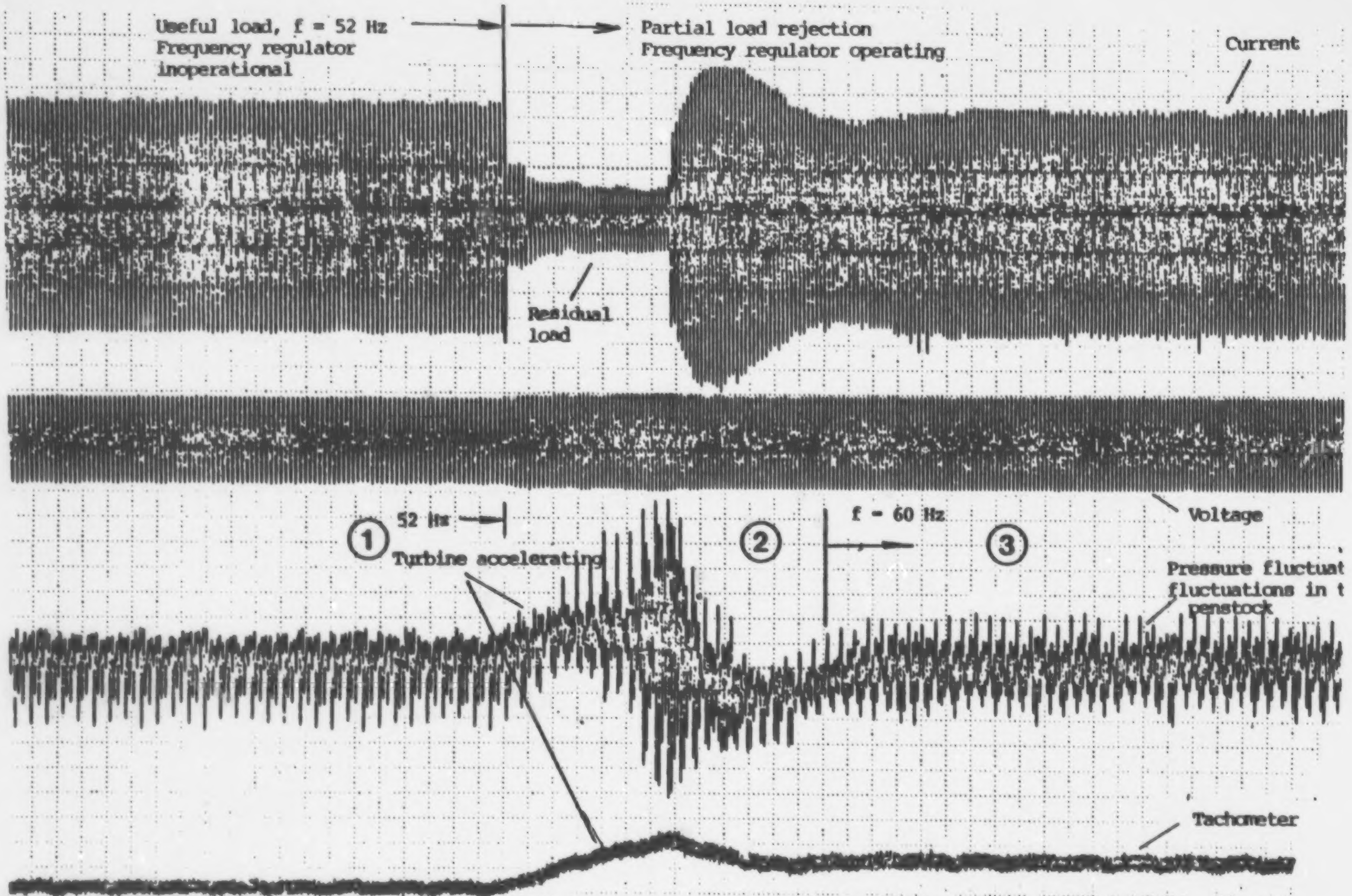
The shape of f(t) is independent of
the initial industrial load as long
as the final load is below or equal
to the turbine rated power.



Frequency variation from 65 Hz to 51 Hz resulting from a sudden load demand.

Voltage regulator in action 240 V
Frequency regulator not working

Fig.1.6.10



perating sequence
1) Frequency of 52 Hz due to applying an appropriate load. Frequency regulator not working (feedback loop open, control load not connected).
2) Partial rejection of the useful load
3) Frequency regulator in action (feedback loop closed and control loads branched as soon as the frequency is f = 60 Hz).

Fig.1.6.11

Methodological Approach for Generation of Appropriate Technology

By
J.S. Gho, T.R. Fonseca

2

CENTRO DE EXPERIMENTACION EN TECNOLOGIA APROPIADA
TEKHNE
Ureta Cox 1034 Tel. 5516056
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Santiago - Chile

THE MICROHYDROPOWER STATIONS:
A Example of Appropriate Technology

By Engineer JAVIER GHO (TECKHNE)

Audio-Visual (35 minutes)

There exists today a big interest in renewable sources of energy like biomass, tydal, solar, wind and others, to satisfy societies energy needs. Many of these technologies have been in use for centuries, and are now again objects of interest. The generation of mechanical force or electrical energy is no exception. In fact, it has been in use for centuries and was seen as a product of industrial development as large installations are seen today.

The introduction of Appropriate Technology Generation will be determined by the interaction of the necessities, means and resources. If we add to this community participation, local creativity and a good knowledge of the socio-economic reality, we will be able to take advantage, with success, of this Appropriate Technology Generation process.

The hydroelectric centrals can be classified according to their power potential as large, small, mini and micro. The microcentrals are are those having a power output of under 100 Kilowatts. There are two types: run-of-the-river plants and dam.

In the run-of-the-river plants the water is not stored. They are the most common type installed in the highlands zones where the topography makes it possible to use the water falls. The Dam Works are most common in the flat zones. The water is stored in reservoirs. The dam itself creates a water fall and has the advantage of accumulating water when resources are seasonal or originates from an intermittent source. Because of civil works, it is necessary to flood the grounds, which makes it much more expensive than the run-of-the-river plants.

In both cases the energy conversion is the same. It consists mainly of the transformation of potential energy to kinetic energy and later to mechanical which is finally converted to electrical energy with the help of a generator.

In developing a hydroelectric central, the first thing that must be done is to determine the necessities of the users:understand mainly inquires like the socioeconomic characteristics of the chosen region, the nature of requests to satisfy. All of this would better said if it is with profitable or domestic purposes, or both. At this stage it is essential that there is community participation, because only by identifying the necessities is it possible to quantify the energy demand.

Secondly, it is necessary to make a quantization of the resources, ie. is it a stable resource or does it have seasonal variations. This will enable us to determine whether it is necessary to accumulate water in a dam, or if it will be sufficient with only a ridge water plant. To do this we must consult with the people who have observed and measured the flow of the river during the year. To measure the flow, if there is a little duct, we can use a pail and watch. If this is not possible we can make a dumping ground according to certain specifications that will enable us to refer to certain numeric tables to determine the flow. There are also other methods in common use that may be used.

Another parameter to be considered is the gross head, the difference in the levels between the pipeline entrance of loan and the turbine. This can be measured in an easily with a water level ascending the pendent and then adding the corresponding heights. By considering the design flow and knowing pipelineloan type, diameter and large we can appraise the loss by friction which is subtracted from the blockhead. Through the formula introduced we will know the resource available potency. In this calculus it is assumed a total rendition turbine-transmission-generator of fifty-one percent (51%).

The third step is to decide the type of installation we need. With the design flow and net head we will know which type of turbine is appropriate.

Forth, we must determine the expenses of the microhydrogeneration system which includes civil works, like clearing of sand, storeroom machines, canals, and so forth.

Participation of the users on the works will reduce the enormous cost. In figure 1, the darkened zone show the cost ranks when there is no local participation.

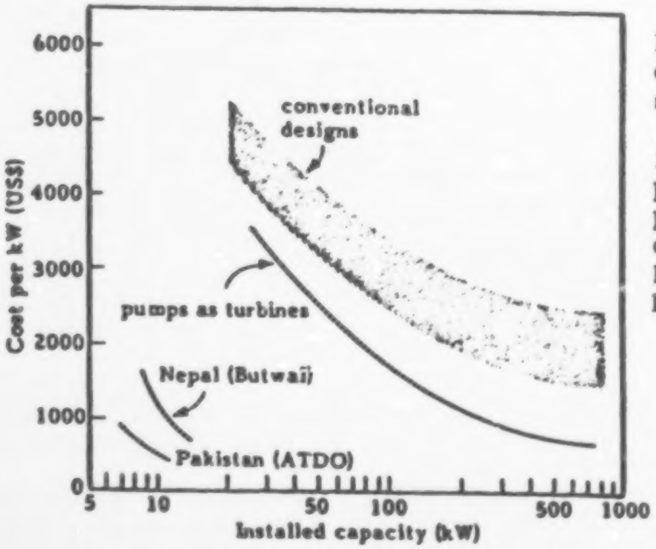

Fig. 1 Cost curves for different approaches to small hydrodevelopment. (Source: Clark, P.J. "Cost implications of small hydro power systems" in "Selected papers in minihydro development" Caribbean Development Bank (TEU) Marzo (1981)

Fifth, we must insure that the cost it will incur to complete the work along with operation expenses, and maintenance are not larger than the cost to connect to the electrical network -if it is possible. Otherwise other systems such as Diesel generation, photovoltaic or others are available on the market are better to be implemented.

The acceptable cost of a hydrogeneration project will depend upon the other alternatives mentioned earlier, and the more accessible and known in the rural sector, Diesel generation. In figure 2 a comparison is made of generation expenses in a one hundred (100) kilowatt hydro plant and similar diesel type. Clearly, when the maximum capacity is utilized for a long period of time, the microcentral is much ore economic. This is possible because in the microhydrogeneration there is no combustible substance consumption.

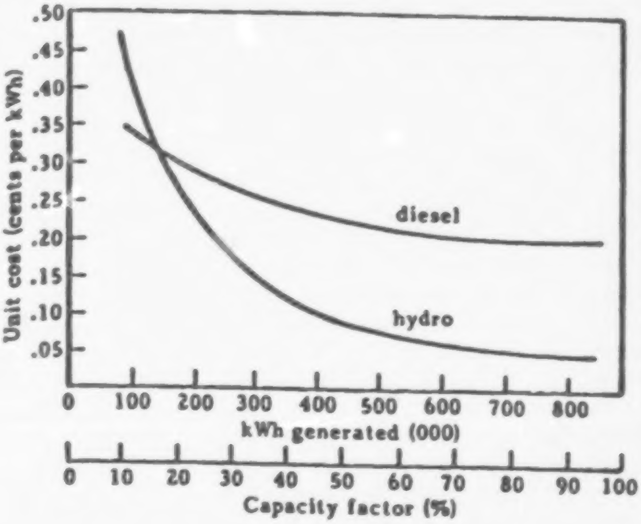

Fig. 2 Effect of capacity factor on unit cost of prod. (100 kW plant). These statistics assume that the hydro capital cost is $3,000 per kW; diesel capital cost is 15% of capital cost for hydro, 4,5% for diesel; fuel cost for diesel is 18 cent per kWh; useful life is 30 year for hydro, 20 years for diesel; interest rate is 12%. (Source: Clark, P.J. ibid.)

Sixth, we must determine the financial alternatives, which is the users willingness to pay, and the type of loan we will recur. Otherwise we will have to see if there are other finance possibilities.

The seventh step is decisive because we have to see if it is possible to build the system ourselves, or buy the microcentral.

In many places there exist workshops of melting where experienced master-workman build spare parts of they conceive the way to repair machines. For example the Pelton Wheels can be manufactured by the Lost Wax method, melted in aluminum, then connected directly to an electric generator relatively easily.

Because of the undulating topography in the Andean zone plus the problems caused by the absence of electrification in the rural sector, serious problems occur by a deficiency of watering. Where ever the river has relatively uninterrupted regimes and a sufficient potential for the necessities, they are useless due to technical-economical impossibility of raising this water to cultivated hillsides.

This is the problem in the Ubaque zone, thirty-five (35) kilometers from Bogota, where an irrigation system existed for years. The water descends by gravity from the hills through polyethylene hoses. The cost is expensive, within reach of only few people, because of share in money and water that must be paid for the hoses to pass over foreign fields. However the popular talent many times defeats the nature, and this is what it did to Mr. Jesus Linares.

The Pump built and development by him, called the Linare River Pump, is supported by the same principles as the old water wheels in which the currents turns a paddle wheel generating mechanical work. This is useful for agricultural process, industry or extractive-mining. The Linares River Pump is made of a metallic structure that has three irons ready to be nail as legs that can be adapted to irregular ground, to avoid being dragged by the river flow. It has a metallic water wheel a hundred and 20 centimeters in diameter, which is arranged in the direction of the current. This operates two pumps that impel the water toward the cultivated hillside. In this manner it is possible to solve, in a practical way, a problem. But a self-taught invention can be improved. The Andes University,sponsored by the GTZ of Germany has a project to technically and economically improve the water-pumps. A variety of prototypes have been assayed at the laboratory scale to test their characteristics. This resulted in several different models. Two of the river-pumps accumulated desirous characteristic. The first one is plains-paddles and its structure is a floating type. The other is made of buckets, the base pattern has been manufactured out of wood, and the definitive scrolls are made of fiberglass.

In this manner Appropriate Technology has been created. Born from the quantization and ingenuity of a self-taught person, Mr. Jesus Linare, and with the experience aid of technician, it has improved the life quality of country men and women.

In the San Luis region, Antioquia, the nongubernamental organization called "Comunidad por los nihos" where the TILAPIA is cultivated. The purpose of this farmhouse is to make the quality of life in the rural areas better, through children, with the development of Appropriate Technologies.

An approximate estimate of power can be obtained from a water falls states that from every liter of water it is possible to generate five (5) watts of electrical power. The hydroelectric generator that is at the farmhouse "Fuentes Clara: has a net head of forty-six (46)) meters, a flow of twelve (12) liters per second and a capacity of twenty seven hundred and sixty (2,760) watts of power.

It works on on three jets and a PELTON turbine with a seven (7) inch diameter which is connect directly to the generator, not needing the transmission. It is made of aluminum and was manufactured through the lost wax procedure. The speed control is obtained through the jets interference.

With the intention of keeping a high charge factor, the house has an electric 200 watt heat storage cooker, the same type used in Norway. In this way it is possible to cook with the electricity of a little generator, with a fourth part of consumption compared with a common electric boiler.

On the highway to Medellin, twenty-five kilometers from San Lus on the side of a bridge, over the Dormilon River there is a barn called "Aire del Dormilon" (Dormilion Airs). It is owned by Mr. Oliverio Duque, an enterprising "fellow" who built his microcentral on a raised hill. In this installation the faucet is located under a rock which Oliverio made a hole in and latter refilled it with concrete and stones. The faucet flows into a sand catcher pool where the eight (8) inch diameter load pipeline starts. It extends forty-two (42) meters with a gross head of twenty-one point five (21.5) metres.

The generator is a single generator and is made through pulleys and two transmission belts. The operation flow is twenty (20) liters per second with four jets set is such a way that the speed-control is performed by the jets interception. The turbine is made of melted iron and has a low effectiveness because its old design. However, the energy produced is enough to make permanent use of an icebox, two coolers, coffee pot, television set, lighting, musical equipment and a radiotelephone. Because of the ice-box and coolers are in constant use, the average energy consumption at the barn is around ninety percent (90%) of the produced energy.

Ten kilometers from San Luis, on the shore of the Dormilon River there is a community installed twenty (20) kilowatt microelectric power station. This microcentral serves two purposes. It produces electricity for lighting and cooking and supplies mechanical work in the community sawmill.

The civil works covers a branch faucet of the ditch which through a hang up pipeline carries the water towards a sand-catcher. The pipeline system is large, four hundred and twenty (420) meter, and there is a brut-head of sixty-six (66) meters. Considereing the head loss on the pipeline we get a gross head of fifty-one (51) meters. A chimney was installed in the the middle of the pipeline loaned to let the air out when the water-pipeline was filled.

The turbine used is a PELTON type with twenty-nine (29) buckets and a diameter of thirty-six point six (36.6) centimeters. The flow is fifty-eight (58) liters per second. It works with two jets and does not have air valves but has a mechanical system with deflectors in the form of a "U" that permits a blockade of the jets manually. A drivind axle enables the sawmill and the generator to work simultaneously. It was necessary to install an electrical system to distribute and compensate the houses demand as much as the sawmill whether is is working or when it goes into operation. The electronic control works in such a way that when there is only demand from the houses it disperses the excess energy into a system of submerged resistance, and in the opposite case the energy is distributes preferably to the sawmill.. As the users do not use all the energy available the charge factor is increased through the use of electric head storage cookers in every house.

The Colombian Amazon at the present time is a region being colonized. In the Pradera, about thirty-five (35) kilometers from the border of Brazil, we found another example of what microhydrotechnology is in a country whose national sport is bicycling. This microcentral is made with a bicycle wheel. It works with a flow of one point six (1.6) liters per second, a gross head of twelve (12) meters producing sixty (60) watts. The energy produced is stored and accumulated in a six watt (6) motorcycle battery which has a maximum charge of six (6) ampere hour. It also has a wave rectifier that is made in a refer of four (4) diodes. The energy generated is destined light the house with little bulbs.

SESSION 5:

TURBINES ' A'

Chairperson: D. DeMontmorency
Rapido Technologies

Applications of Submersible Hydro Turbine Generators - A Novel Approach

By
Z. Czarnota

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Small Hydro 88 - An International Conference and Trade Show. July 4 - 9, 1988 in Toronto, Canada.

Session: Turbines A

Title: Applications of submersible hydroturbine generators - a novel approach.

Author: Dr. Zbigniew Czarnota, Flygt AB, Sweden

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1. Introduction

Minihydro and minicomputers have one thing in common - they are not just scaled-down versions of their bigger predecessors. In both cases original ideas and innovative designs were required to succeed on the market. A number of new companies devoted exclusively to the respective "mini" - concept set the trend. The established manufacturers had to follow the suite in order to join the expanding business.

The main trends in the development of mini hydro have been:

1) Standardization of mechanical equipment.

2) Package solutions.

3) Simple civil structures.

At the same time the demand for high efficiency of the equipment remained uncompromized, which precluded large-scale use of pumps as turbines.

2. Submersible hydroturbine generators

One of the most interesting innovations on the market have been submersible hydroturbine generators. A single unit integrates an axial flow turbine, a planetary speed increaser, if necessary, and an induction generator. The turbine is manufactured in six standard sizes with runner diameters from 550 to 1500 mm (22-59 in), Fig 1. The runner can have manually or automatically adjustable blades. The turbine is designed for heads ranging from 2.5 to 20 m (8-66 ft), and a flow rate from 0.5 to 12 m^3/s. (18-420 cfs). The generator capacity ranges from 20 to 530 kw.

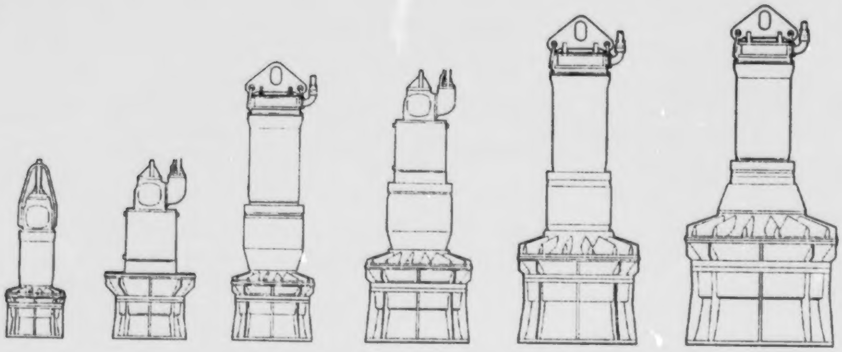

Fig. 1. Range of submersible hydroturbine generators

3. Application of submersible hydroturbine generators

The submersible hydroturbine generators have found a broad acceptance which is proved by over a hundred stations built in North America, Europe and Asia, within the last five years - 44 of them in the USA and Canada alone.

Submersible hydroturbine generators are particularly suitable for low head developments, for which the size of the turbine is large in relation to the size of the generator. Their main advantages stem from the principle of installing the entire generating unit within the waterway, thus eliminating the need for transmission of mechanical power and eliminating the conventional power house. Consequently the civil structures can be simplified and greatly reduced in size. Since site alignement of shafts and embeddement of the machinery parts in concrete is excluded, local labour and simple construction equipment can be used to erect a power station. Moreover the installation of submersible hydroturbine generators can be easily adapted to specific site conditions offering aesthetical and environemental advantages.

4. Installation principles

The submersible hydroturbine generator is most conveniently installed in a vertical tube with a bottom flange which serves as a turbine seat and connects a draft tube. The own weight of the machine is sufficient to keep it inside the seat without additional fastening, which is a great advantage from the installation and service point of view. This installation principle is equally suitable for both hydraulic systems, open channels and closed conduits. The turbine tube can be joined with a penstock, or installed in an open flume or a closed chamber.

5. Basic installation layouts

In order to exploit the unique qualities of the submersible hydroturbine generators, four basic station layouts were developed to match the most common site conditions within the head range from 2.5 to 20 m (8-66 ft). Despite their simple geometries the stations provide ideal flow conditions for the turbine, which gives a high total water-to-wire efficiency. The most critical parts of the design, such as the flume configuration, the submergence of the intake and the siphon geometry, were studied in hydraulic models. The tests allowed us to optimize the station design from the constructional point of view and yet maintain the efficient hydraulic operation free from problems related to vortices, cavitation, instabilities and vibrations.

Penstock

A penstock installation, (Fig 2), is suitable for a head greater than 6 m, (20 ft). It consists of a horizontal or inclined penstock, a Y-junction, a vertical turbine tube and a draft tube. The flow can be controlled by a valve installed at the lower end of the penstock or by a sluice gate at the intake.

Four variations of the penstock installation can be distinguished here. Two types of draft tubes, straight or elbow can be combined with a turbine tube of a nominal diameter for moderate flow rate, or a turbine tube with an increased diameter for a greater flow rate. The elbow-type draft tube is more convenient if a low runner setting is required. Otherwise the straight draft tube is prefered because of its lower cost.

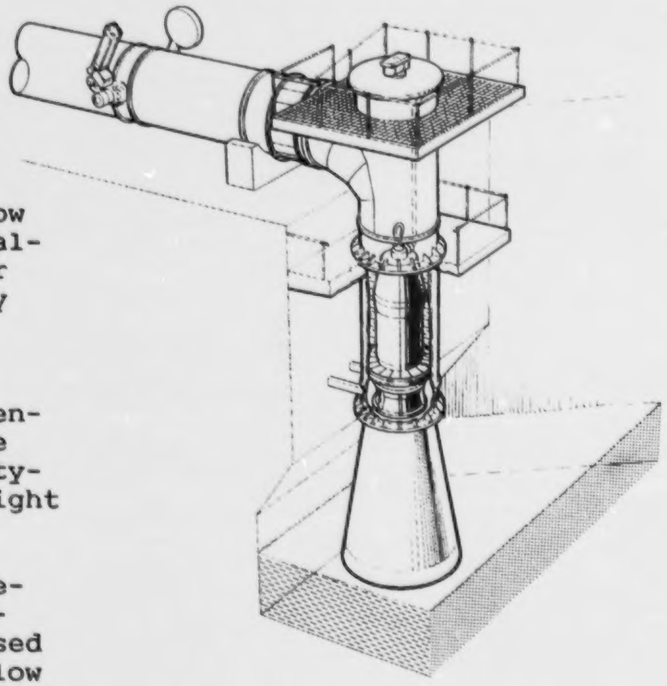

Fig. 2. Penstock installation

Open flume

An open flume installation with a straight draft tube (Fig 3), can be most suitable for a head range from 5 to 10 m, (16-33ft). The main elements are a short flume, a turbine tube and a straight draft tube. The flow is controlled by a sluice gate. The optimum width of the flume is twice the nominal turbine tube diameter. The positioning of the turbine tube near the back wall of the flume, together with the corner fillets, prevent formation of vortices at the turbine intake and allow a uniform distribution of flow.

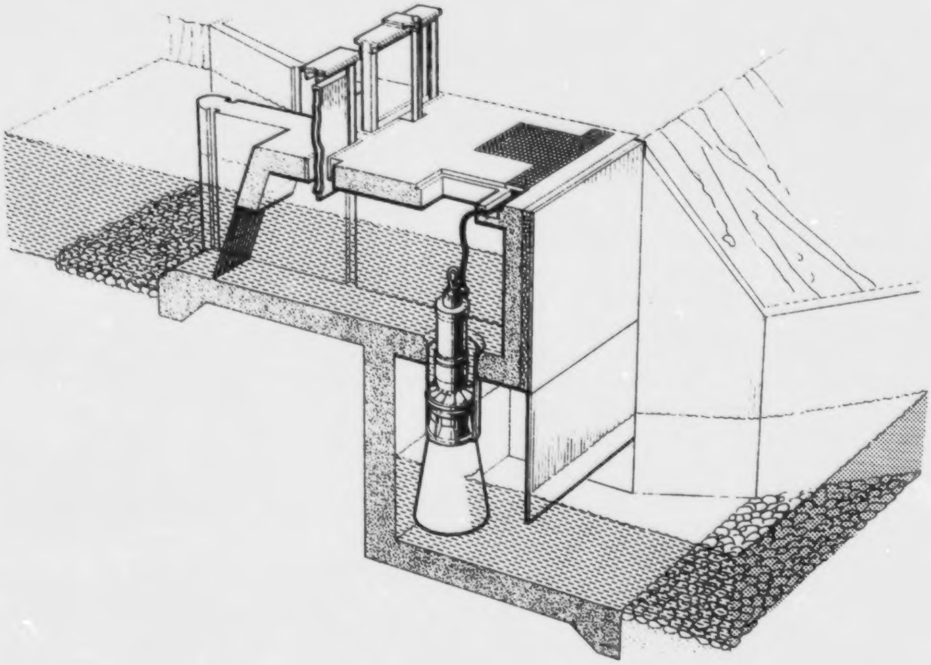

Fig. 3. Open flume installation, straight draft tube

For a still lower head, from 3 to 6 m, (10-20 ft), an open flume with a conventional elbow draft tube, Fig 4, is most advantegeous. The same flume geometry as above is recommended. Here the flow is controlled by a cylinder gate. The cylinder gate is simply a piece of pipe with a rubber seal around its lower circumferance. Since the hydrostatic pressure on the cylinder is balanced, the gate can be moved up and down with very little friction. It can also be closed by its own weight which is an important safety feature. The cylinder gate or a sluice gate can alternatively be used in all types of open flumes.

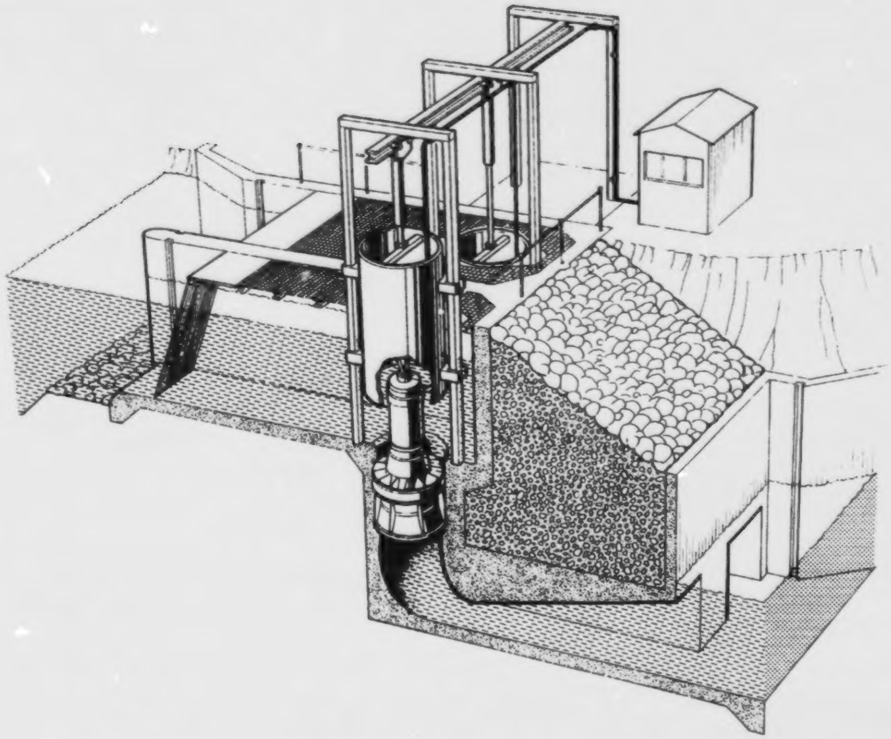

Fig. 4. Open flume installation, elbow draft tube

Siphon

For a very low head, 2.5-5 m, (8-16 ft), and a relatively large flow, 5-10 m^3/s, (175-350 cfs), a siphon installation can be most convenient, Fig 5. Such a power station whose turbine chamber operates as a siphon can be incorporated into a dam or an over flow weir. The main advantage of such a siphon is that the excavation depth for the foundation of the station is reduced as compared with open flume installations. Since the inlet bellmouth is placed above the head water level, the turbine can be installed just at the water level, which is at least two runner diameters higher than for the open flume.

A siphon installation does not require a gate. The flow is initiated by a vacuum system, which evacuates the air from the chamber and it can be stopped by admitting air into the chamber. Such a system with few moving parts is advantageous in cold climates as it reduces the risk of freezing.

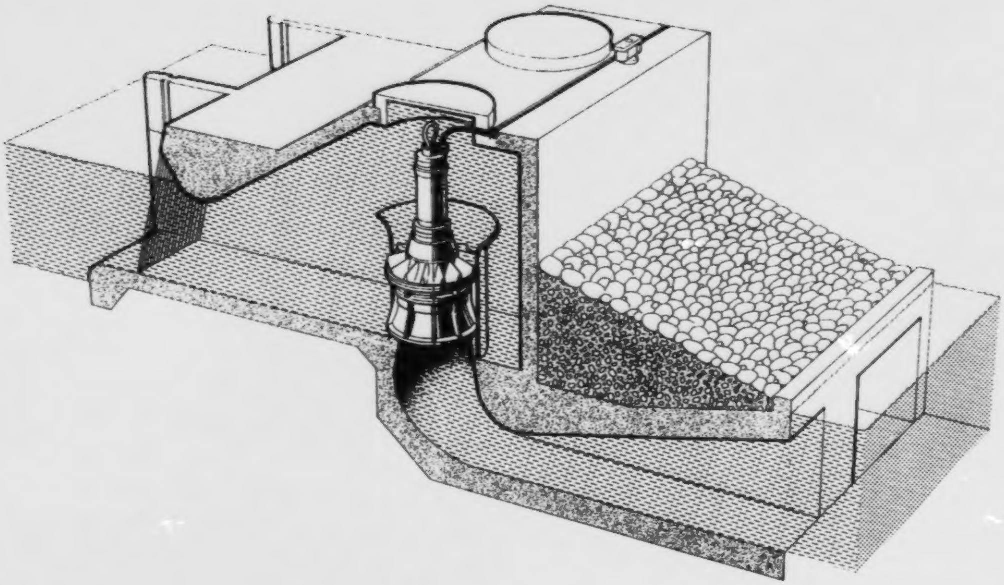

Fig. 5. Siphon installation

This particular design has been extensively tested in a hydraulic model and it combines an optimum of a simple geometry and an excellent hydraulic function. The flow distribution at the turbine inlet is uniform and priming of the siphon is greatly assisted by turbulent mixing of air with water in the initial stage.

Another type of siphon which can be used even with higher heads is a penstock siphon. Such a siphon can be mounted over an existing dam without interfering with its function and safety, and it can use a minimum discharge from a reservoir which is normally spilled. Again a submersible hydroturbine generator is more convenient for such installations than conventional turbines.

6. Floodproof and underwater power stations

A unique type of applications for submersible hydroturbine generators are floodproof power stations, or even underwater stations. An open flume and a siphon station can be made floodproof by placing the control equipment in safety beyond the reach of floodwater. Only cables and hydraulic lines have to be extended. The hydroturbine generator can operate even with water running above the station as long as the available head allows.

The first floodproof station with submersible hydroturbine generators was built in the upper reach of the Loire river in France. The precondition for construction was that the station does not interfere with the flood flow allowing passage of debris and flood waves of about 6 m (20 ft), above the dam crest. An open flume type installation with three units and cylinder gates was selected. The flumes were covered with concrete decks and the gates were furnished with covers to protect the equipment from debris, which are usually carried in large amount at this site. The control equipment was placed in an old adjacent building on the second floor.

An underwater power station is under construction in West Germany. The station is incorporated into an overflow weir. The minimum flow of 0.6 m^3/s (21 cfs), is always discharged over the weir creating picturesque rapids on the river. The power station is of a closed flume type with the upper deck below the water surface. The flow through the station can be shut-off with a telescopic cylinder gate. The power and control cables from the station are extended to the high bank of the river. At the normal flow in the river a 0.1 m (0.3 ft) thick layer of water passes above the station. The only part of the station protruding above the water surface is a pair of 0.5 m (1.5 ft), high walls which allow installation of stoplogs and access to the machine.

7. Wastewater as a hydroresource

Minihydro in contrast to the traditional hydropower can utilize a variety of energy sources. For example, sewage treatment plants can provide various opportunities for recovering some part of their potential energy. A great number of sewage treatment plants have a significant head drop at the outlet. Treated wastewater can be used there to drive turbines. Such a power plant with a capacity of 30 kW is recently under construction in Italy. Submersible hydroturbine generators again allow simple installation which can fit into an existing plant. But their main advantage in this case is the possibility to take out the assembled generating unit for service and to install it back without the need for the service personnel to enter the turbine chamber.

So far a unique application is a hydroturbine generator installed in a heat-pump plant, which supplies a large part of Stockholms central heating system. The heat pumps recover heat from treated wastewater which is pumped to the station and then discharged to the sea creating a head of 10 m (33 ft). A single hydroturbine generator of 350 kW capacity was installed there to recover about 60 % of the energy used for lifting wastewater within the station.

8. Rehabilitation of old stations

Rehabilitation of old power stations does not necessarily mean restoration of the old machinery and civil structure. Old Francis turbines installed in open flumes can particularly simply be replaced by the submersible hydroturbine generators. After removing the old turbine a turbine tube is installed in its place, usually with a draft tube adapter. Then only the flume and the gate have to be renovated before a hydroturbine generator can be installed. The old power house becomes redundant.

Also a partial rehabilitation of power stations with multiple turbines can be done in a similar way. Then a cylinder gate has to be installed additionally in order to allow independent operation of the submersible unit in a flume shared by two or more turbines. Some thirty old stations were refurbished in that way both in Europe and in North America.

9. Conclusions

The exemplified areas of application for the submersible hydroturbine generators illustrate the versatility of this particular design. In the presented installations, this type of hydroturbine generators can successfully compete against vertical propeller and Kaplan turbines, horizontal or inclined tubular turbines, low head Francis turbines and cross-flow turbines.

At the same time the given examples are only a fraction of feasible applications for the submersible hydroturbine generators. The ingenuity and entreprenuerial spirit of small hydro developers is bound to bring about another innovative and unconventional solutions.

Performance Tests of a New Hydraulic Impulse Turbine

By
G. Chiatti, R. Ruscitti

4

PERFORMANCE TESTS OF A NEW HYDRAULIC IMPULSE TURBINE

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SUMMARY

A new hydraulic turbine, especially suited for mini-hydro plants due to high modularity, wide range of application at good efficiency and compactness, has been tested.

The machine may be considered a further development of a Mitchell-Banki turbine in which an internal rotating deflection element has been introduced inside the blade crown to guide the stream and avoid focusing effects.

A small size prototype has been constructed and tested to ascertain the turbine performances.

Experimental results are reported for the hydraulic, mechanical and overall efficiency at various load and operating conditions.

1. INTRODUCTION

Great emphasis has been put in recent years, due to economic and environmental considerations, to renewable energy sources, and there has been new interest in hydroelectricity, mainly on mini-and-micro-scale.

In addition mini- and micro-hydro-plants have become of primary importance in the solution of energy problems of many developing countries [1].

However specific capital costs of small-hydro-plants are higher than those of big ones and morever the cost of mechanical and electrical equipment is dominating [2, 3].

As the economic success of small-hydro is chiefly related to the considerable reduction of both machinery and civil works fee, a new and specific approach to machines design and production is required.

So, due to the necessity to lower costs, standardization criteria have been brought into small hydro-turbine manufacture from other production areas where they have had a long history.

From this point of view, new interest and extensive studies have been devoted to some earlier machine schemes, whose development was blocked by the rise of the high efficiency classical hydro-turbines [4, 5].

In order to achieve high modularity, broad standardization capabilities and thereby very low construction costs, new hydraulic turbine have been conceived, extensively studied and made in the Dipartimento Meccanica e Aeronautica of the "La Sapienza" University of Rome [6, 7].

Performance tests of one of them are here reported. This new impulse turbine (fig. 1) may be considered similar in shape to a Mitchell–Banki one, but the introduction of a rotating deflection element inside the blade crown (fig. 2) to guide the stream and avoid focusing effects on flow paths, gives it quite a peculiar operational behaviour. Two subsequent jet tranches flow along the surface of a cylindrical blade: the first, directly coming from the nozzle, is sent towards the deviator cavity; the second, received by the immediately following blade and reversed by the contiguous deviator hole, flows in an outward direction. A good deal of previous theoretical and experimental work was spent in seeking and verifying the conditions of a proper flow at deviator edges.

Earlier series of running tests of the turbine prototype were devoted to study flow paths inside the rotor, performances of machine–elements and overall turbine efficiency [8].

A deeper analysis of the efficiency and of the influence of geometric and operational parameters is here undertaken.

Singular amounts of hydraulic, volumic and mechanical losses are evaluated and experimental results in close agreement with theoretical computations are reported.

2. TURBINE EFFICIENCY

In order to investigate the influence of the geometric and functional parameters on the turbine performances, efficiency has been split into factors:

$$\eta_t = \eta_h \cdot \eta_v \cdot \eta_m$$

where the turbine efficiency η_t, is the ratio of the actual power at turbine axis over the available hydraulic power at the turbine entrance; the hydraulic efficiency η_h, is the ratio of the power released on the runner by the unity of mass flow rate acting on it and the corresponding specific available power; the volumic efficiency η_v, is the ratio of the power actually released by the flow on the runner active surfaces over the one that would be released if the all jet would completely work; the mechanical efficiency η_m, is the ratio of the power at turbine axis over that released on the runner.

The above–mentioned efficiencies are analyzed in the following subpoints in order to draw theoretical graphs as reference–curves for experimental measurements.

2.1. Hydraulic Efficiency

The hydraulic efficiency is evaluated by means of the Euler equation and the unidimensional theory. A sufficiently good approximation is expected, and will be verified, because water flows in a plane motion and the jet width is small, when compared to the runner dimensions.

Considering the control volume inside the cylindrical surface round the outer radius of the rummer, the specific power per unity of mass–flow–rate acting on the blades is

$$P_h = u(c_i \cos\alpha_i - c_o \cos\alpha_o)$$

where u is the peripheral runner speed; c is the absolute jet velocity; α is the angle between u and c; the subscripts i and o denote incoming and outcoming quantities.

By means of the ratio of the relative velocities, $\psi = w_o/w_i$, and the angle, β, between u and w, the above equation becomes:

$$P_h = u(c_i \cos\alpha_i - u)\ (1 + \psi\ \frac{\cos\beta_0}{\cos\beta_i})$$

with:

$$\cos\beta_i = \frac{\cos\alpha_i - u/c_i}{\sqrt{1 + (\frac{u}{c_i})^2 - 2\ \frac{u}{c_i}\ \cos\alpha_i}}$$

Introducing a nozzle loss coefficient, $\varphi = c_i/\sqrt{2P_a}$, P_a being the available power, the hydraulic efficiency, $\eta_h = P_h/P_a$, can be written:

$$\eta_h = 2\varphi^2\ [\frac{u}{c_i}\ (\cos\alpha_i - \frac{u}{c_i})\ ]\ (1 + \psi\ \frac{\cos\beta_o}{\cos\beta_i})$$

and, finally, in terms of the speed ratio $v = u/c_i$ and of the geometric and functional parameters α_i, β_0, φ and ψ:

$$\eta_h = 2\varphi^2 v\ [\cos\alpha_i - v + \psi\ \cos\beta_o\ (1 + v^2 - 2v\ \cos\alpha_i)^{1/2}]$$

For the prototype under test the geometric parameters α_i and β_o are:

$$\alpha_i = \arccos[\frac{r_e - (\sigma + s/2)}{r_e}] \quad ; \quad \beta_o = 37°30'$$

where r_e (= 125 mm) is the external blade radius; s is the jet-width; σ is the maximum rise of the arch of the external blade circumference cut by the lowest flow filament.

Standard values $\varphi = 0,96$ and $\psi = 0,96^2$ have been assumed in the calculations, bearing in mind corresponding Pelton parameters.

Actual values of φ for the turbine-nozzle under test are obtained from flow-rate and inlet pressure measurements (fig. 3).

The graph of hydraulic efficiency versus speed-ratio is drawn in fig. 4.

2.2. Volumic Efficiency

Performance-decay due to a partial flow-action on the runner surfaces is accounted for by the volumic efficiency.

Two different phenomena take place at low and high speed-ratios, i.e. below and over 0.5.

As running speed increases, a portion of the jet cannot reach the blade just in front of it and therefore the associated energy is completely lost. This jet-fraction that cannot be caught by the runner may be computed on the basis of the relative trajectories of the blades towards the jet.

Blade external tips move along trochoidal curves that sharpen as running speed increases, so that the jet is no longer completely restricted within blade trajectories, as shown in fig. 5.

The trochoids equation can be written in a $x - y$ plane as:

$$\frac{x}{r_e} = \frac{c_i}{u} \arccos \left(1 - \frac{y}{r_e}\right) - \left[1 - (1 - \frac{y}{r_e})^2\right]^{1/2} + n \frac{2\pi}{z} \frac{c_i}{u}$$

where n is a real integer and z (= 24) the number of blades.

Volumic efficiency is then expressed by the ratio of the portion of the jet inside the blade trajectories, evaluated by integration of the trochoids in the plane of fig. 5, to the total jet–area.

At low running speeds, flow, reversed by the deviator, impinges on internal blade edges and is partially entrained inside the rotor, as shown in fig. 6.[1]

The entrained jet–fraction f, cannot release energy in the second blade passage.

Volumic efficiency is then computed as the ratio of actual specific power, the weighted mean of those supplied by the entrained fraction, P_e, and by the fraction correctly crossing the runner P_h, to P_h itself:

$$\eta_v = \frac{f P_e + (1 - f)\, P_h}{P_h} = f\, \frac{P_e}{P_h} + (1 - f)$$

Assuming that the entrained flow is flung off the runner with a tangential component of absolute velocity equal to the peripheral speed, based on velocity triangles shown in fig. 7, the corresponding power can be written as [ref. 2.1):

$$P_e = u(c_i \cos \alpha_i - u)$$

Volumic efficiency is then:

$$\eta_v = 1 - f\, (\frac{\psi'}{1 + \psi'})$$

where:

$$\psi' = \psi\, \frac{\cos \beta_o}{\cos \beta_i}$$

The entrained jet–fraction f, is computed as the ratio of the jet–width impinging on the blade internal edge to the total jet width. Referring to fig. 8, the internal blade radius being r_i, ϑ_e the entrained jet angular width, ϑ_o the angular width of the jet–path between deviator and blade, ϑ_ω the angular displacement of the blade during the time a water particle crosses the path and ϑ, the deviator–to–blade phase angle, the width of the jet–fraction impinging on the internal edge of the blade s_e, is expressed as:

---

[1] Fig. 6 also shows that a portion of the jet is directly sent out off the runner, reversed by the blade itself, giving rise to a sort of "Pelton effect", that however does not influence the hydraulic power and efficiency equations

$$s_e = r_i \, \vartheta_e$$

being:

$$\vartheta_e = \vartheta_0 - \vartheta_w - \vartheta_s$$

The total jet–width s_t, as related to the jet–width at the nozzle, s, is:

$$s_t = s \, \frac{c_i}{w_{i,o}} \, \frac{1 + v^2 - 2v\cos\alpha_i}{1 - v\cos\alpha_i}$$

$w_{i,o}$ being the corresponding relative velocity.

The impinging jet–fraction, $f = s_e/s_t$ can be then expressed as:

$$f = \vartheta_e \, \frac{r_i}{s} \, \frac{w_{i,o}}{c_i} \, \frac{1 - v\cos\alpha_i}{1 + v^2 - 2v\cos\alpha_i}$$

The complete formulation of the above parameters is reported the Appendix.

2.3. Mechanical efficiency

Since it is impossible to directly measure the power actually released by flow, mechanical efficiency is computed by means of the power measured at turbine axis P_r, and the power of mechanical losses P_m:

$$\eta_m = \frac{P_r}{P_r + P_m}$$

Friction torque, $M_m = P_m/\omega$, has been estimated by measuring the time spent by the freely rotating runner to stop, starting from various revolution–speeds; the governing equation of the free motion is:

$$M_m + I\frac{d\omega}{d\tau} = 0$$

being I the inertia of rotating elements, ω the angular velocity and τ the time.

Taking into account dry, viscous and aerodynamic friction, M_m has been given the complete quadratic law:

$$M_m = a + b\omega + c\omega^2$$

Resulting integral equation for the time of the arrest of the runner is:

$$\int_0^t d\tau = - \int_{\omega_o}^{0} \frac{I \, d\omega}{a + b\omega + c\omega^2}$$

The unknown coefficients a, b and c are inferred by fitting the curve of revolution–speed versus time–to–stop in with the experimental points by a nonlinear least–squares technique. Results of fitting for plexiglass and metallic blade–supporting disks are reported in fig. 9.

3. EXPERIMENTAL RESULTS

The turbine model, whose main characteristics are reported in Table I, has been secured to the hydraulic test bed of the laboratory of the Dipartimento di Meccanica e Aeronautica, of "La Sapienza" University of Rome. The test bed is equipped with standard orifice–flow–meters connected to differential manometers, inlet pressure manometers, a digital running–speed–meter and an oleodynamic brake mounted on an oscillating support provided with a 0,05N per division dynamometer.

The uncertainty of efficiency measures has been estimated and typical results are shownm in fig. 10. The statistical distribution of the experimental data was controlled by repeated measures of the efficiency and a very narrow Gaussian curve was obtained.

Flow patterns have been examined by photografic and stroboscopic means.

Reported tests have been chiefly devoted to a detailed analysis of turbine efficiency through the evaluation of the singular amounts of hydraulic, volumic and mechanical losses.

Graph of mechanical efficiency is shown in fig. 11.

Volumic efficiency is reported in fig. 12.

Overall efficiency and torque curves at several running speeds are reported in fig. 13.

By adjusting the hydraulic head, turbine design speed was varied from $\simeq$ 200 r.p.m. up to $\simeq$ 500 r.p.m.. Low speed tests allowed the use of plexiglass disks and the stroboscopic and photographic analysis of the flow patterns inside the rotor. Metallic disks were mounted to get over 330 r.p.m.; efficiency tests at low speeds were repeated and the results compared to the plexiglass one.

The influence of absolute inlet angle α_i on maximum efficiency values is shown in fig. 14.

Since a continuous change at the deviator–to–blade displacement during operation was not allowed, no experimental optimization of this parameter was possible. A remarkable influence of it would be expected due to a jet spread inside the runner caused by some construction defects.

4. COMMENTS

The experimental work, revealing some construction deficiencies of the prototype under test, suggested the extension of the flow analysis at reduced running speeds and gave rise to some design refinements in order to further improve simplicity and modularity of the structure of a second prototype, that is going to be tested.

Predicted and observed efficiency graphs resulted similar in shape and close to each other.

The taking in account of mechanical and volumic efficiency greatly improved the analysis of turbine performances. The measurements of mechanical losses made it possible to quantify the reduction of mechanical efficiency at lower power outputs so that, eventhough global turbine efficiency varied widely from nearly 50% to 65%, maximum hydraulic efficiency values fell in a narrower range from nearly 70% to 75%.

The agreement of hydraulic efficiency curves for plexiglass and metallic blade-supporting disks, i.e. for different mechanical efficiencies, validates estimated values and the assumed analytical law of friction torque.

Optimum inlet angle α_i, and deviator-to-blade phase angle, θ_s, are close to theoretical ones, as provided by the design procedure of turbine deviator and blades.

A few refinements of the runner geometry, in order to further improve the turbine efficiency, are expected from a deeper theoretical and experimental flow analysis that will be undertaken by computer codes and the aid of video recording and processing techniques.

Full power tests will be carried out in the near future, from which global efficiencies closer to the hydraulic ones are expected.

In authors opinion, the reported efficiencies encourage the research effort and, together with the low technology requirements and costs, confirm, the capabilities of the new turbine for small hydro- applications.

NOTES

This paper was supported by a PFE2 Grant. Authors' names appear in alphabetical order.

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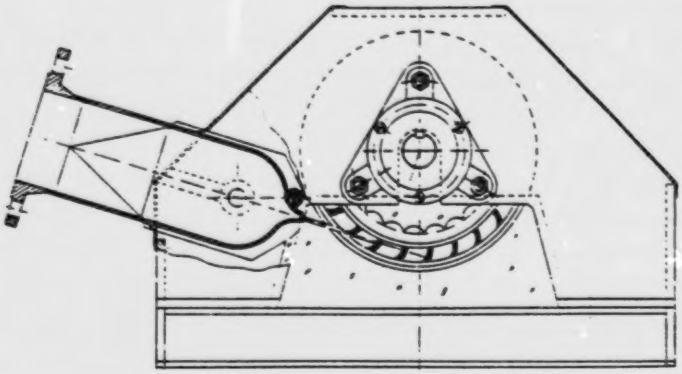

Fig. 1 - Sectional drawing of the turbine.

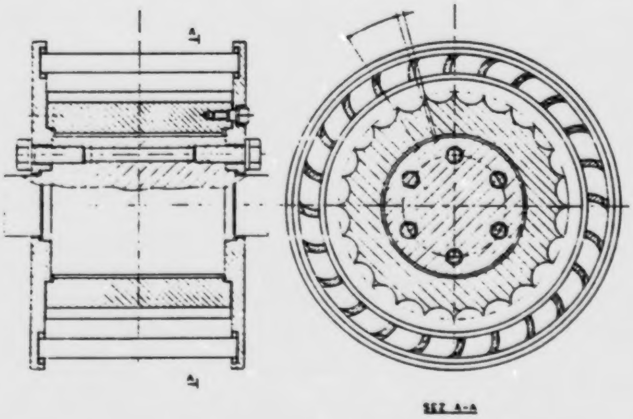

Fig. 2 - Runner sections.

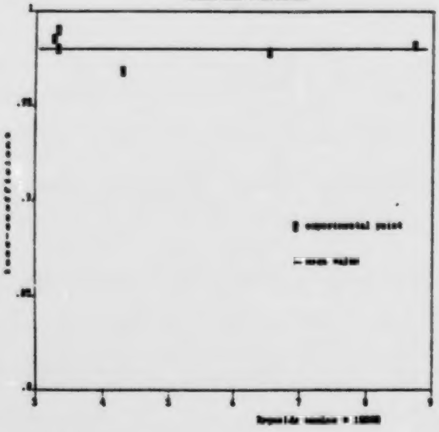

Fig. 3 - Experimental values of φ.

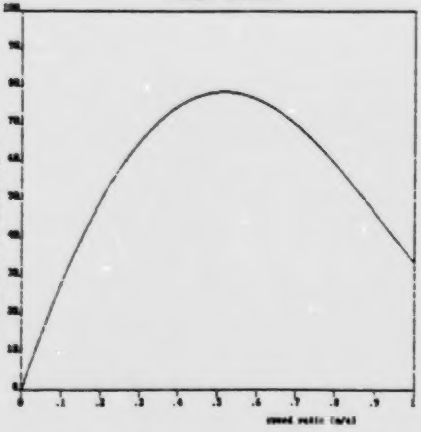

Fig. 4 - Theoretical hydraulic efficiency.

TABLE I

Prototype main Characteristics	
External Runner Diameter	250 mm
Full Load Jet Width	4 mm
Blade Length	145 mm
Number of Runner Blades	24
Specific Camerer Speed	32
Design Power	140 kW
Design running speed	3000 rpm

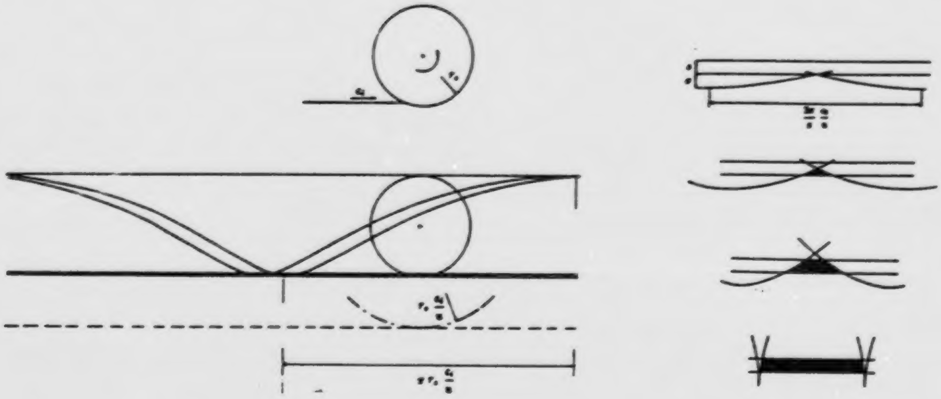

Fig. 5 - Trochoidal trajectories of blade tips.

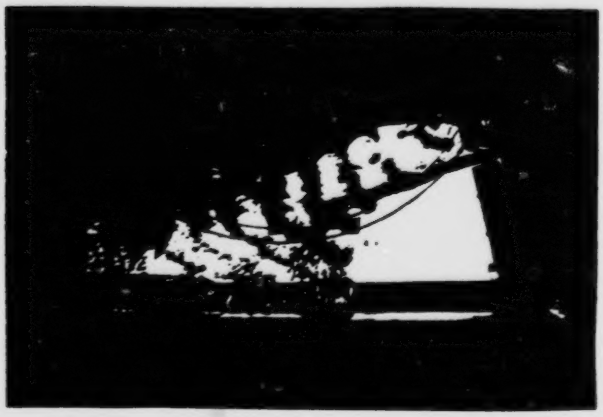

Fig. 6.a - Flow entrainment at low speed-ratio (< 0.5).

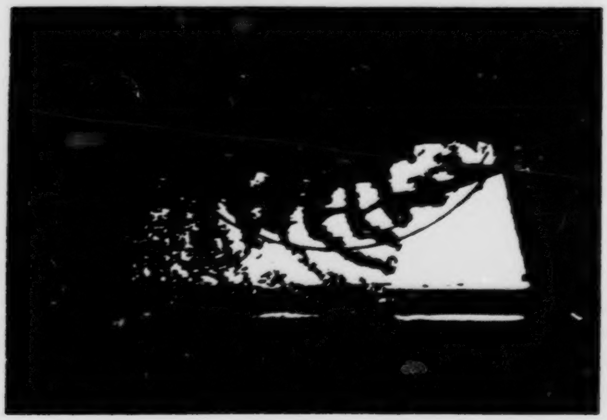

Fig. 6.b - Flow at optimum speed-ratio.

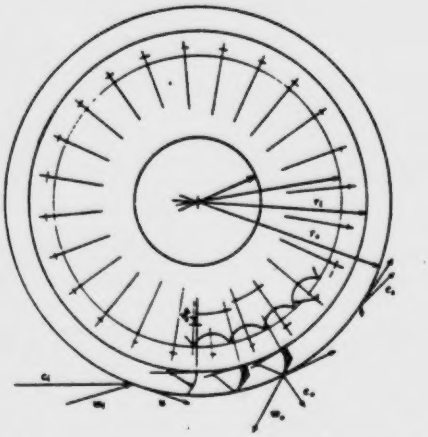

Fig. 7 - Incoming and outcoming velocity vectors.

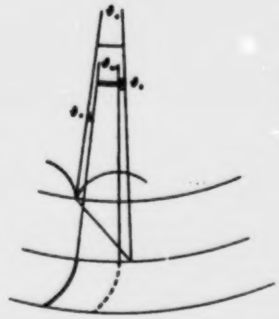

Fig. 8 - Characteristic angles.

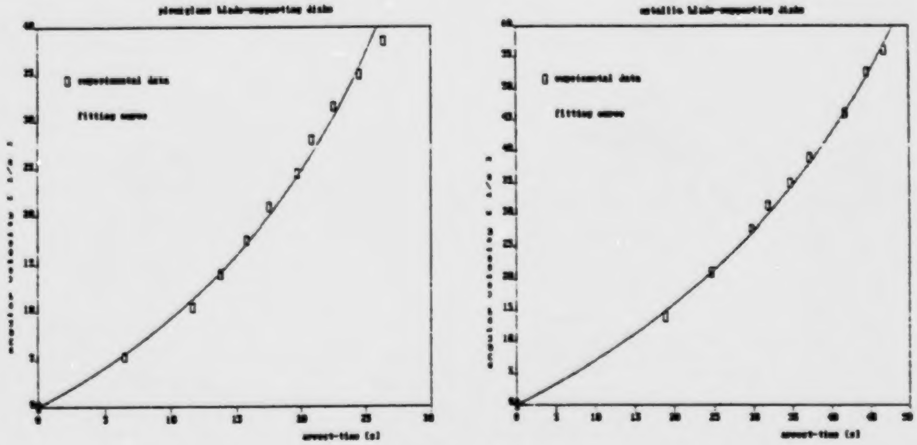

Fig. 9 - Arrest-time fitting curves.

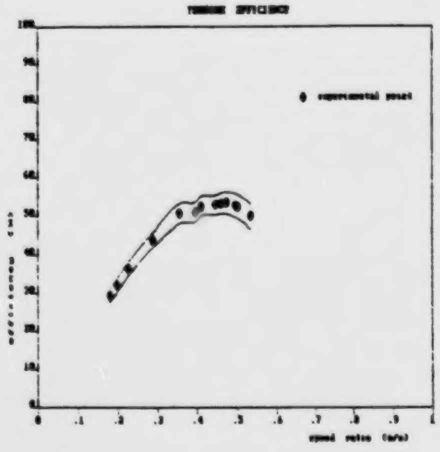

Fig. 10 - Estimated measurement uncertainty.

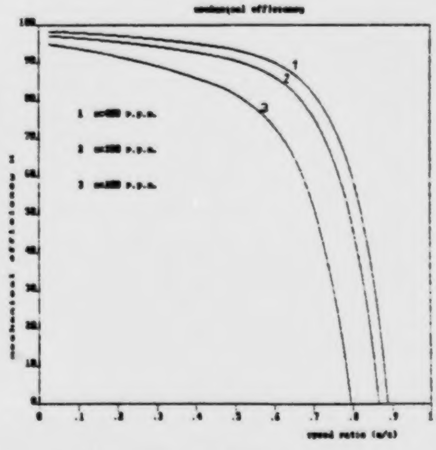

Fig. 11 - Mechanical efficiency.

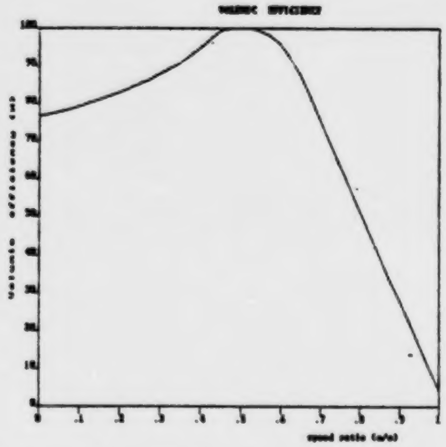

Fig. 12 - Volumic efficiency graph ($\vartheta_s = 1^\circ 30'$ $s = 4\text{mm}$).

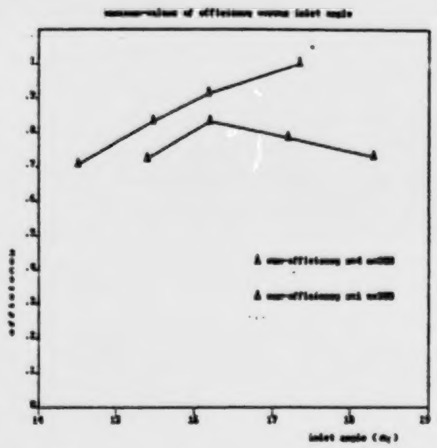

Fig. 14 - Maximum efficiency versus inlet angle.

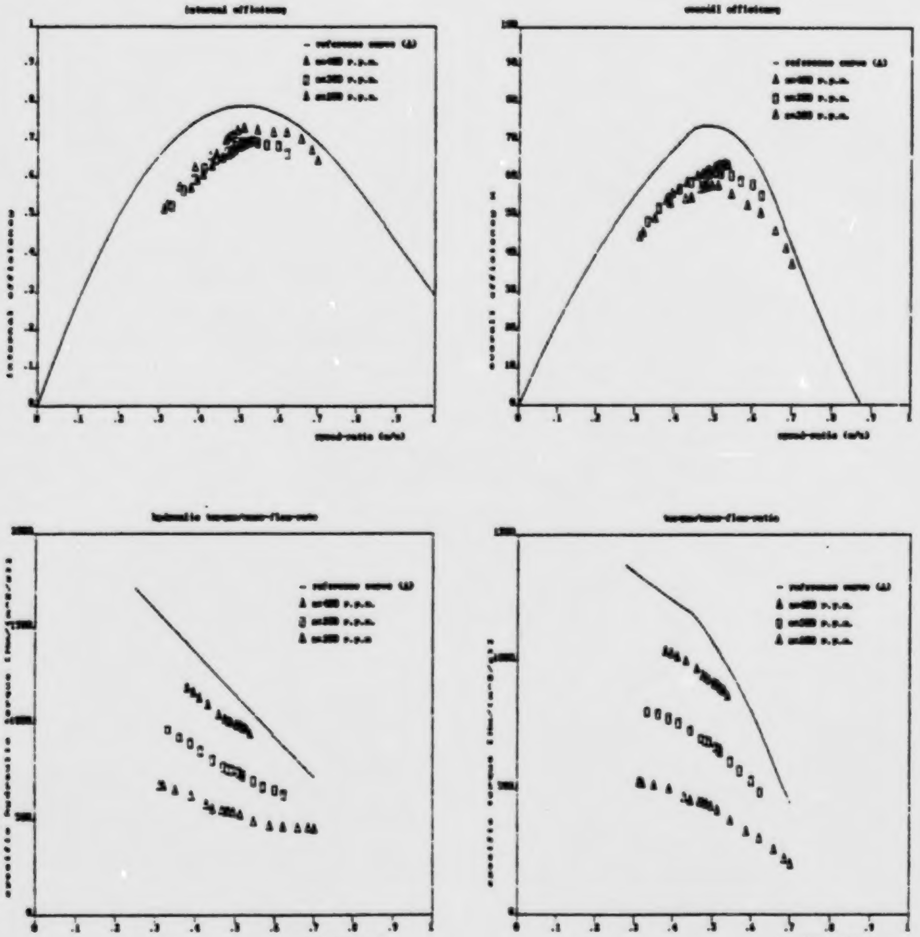

Fig. 13 - Experimental efficiency and torque.

APPENDIX - Entrained jet fraction

Referring to the inlet velocity triangle, fig. A.1, this can be written:

$$w_i = \left(u^2 + c_i^2 - 2c_i u \cos\alpha_i\right)^{1/2}$$

The relative inword velocity, $w_{i,i}$, at blade internal edge is:

$$w_{i,i} = \psi_b^2 \left[w_i^2 - (u^2 - u_i^2)\right]^{1/2}$$

where ψ_b is the velocity coefficient of blade losses and u_i is the peripheral speed at blade internal radius, r_i.

Taking account of fig. A.2 and A.3:

$$c_{i,i} = \left(w_{i,i}^2 + u_i^2\right)^{1/2}$$

where $c_{i,i}$ is the absolute inword velocity;

$$\begin{aligned}
\gamma_{b,i} &= \arctan\left(\frac{u_i}{w_{i,i}}\right)\\
\gamma_{d,i} &= \arcsin\left(\frac{r_i}{r_d}\sin\gamma_{b,i}\right)\\
\alpha_{d,i} &= \frac{\pi}{2} - \gamma_{d,i}\\
w_{d,i} &= \left(c_{i,i} + u_d^2 - 2c_{i,i}u_d\cos\alpha_{d,i}\right)\\
w_{d,o} &= \psi_d w_{d,i}
\end{aligned}$$

where $w_{d,i}, w_{d,o}$ are the incoming and outcoming relative velocities at the deviator–radius, r_d; u_d is the deviator peripheral speed; ψ_d is the deviator velocity–coefficient.

Taking into consideration fig. A.4, A.5, A.6 and .7

$$c_{i,o} = \left(w_{d,o}^2 + u_d^2 + 2u_d w_{d,o}\cos\beta_d\right)^{1/2}$$

(for the prototype under test is $\beta_d = 73°20'$ [7])

$$\begin{aligned}
\alpha_{d,o} &= \arccos\left(\frac{u_d + w_{d,o}\cos\beta_d}{c_{i,o}}\right)\\
\gamma_{d,o} &= \frac{\pi}{2} - \alpha_{d,o}\\
\theta_o &= \gamma_{d,o} - \gamma_{b,o}\\
t_o &= \left(r_i\cos\gamma_{b,o} - r_d\cos\gamma_{d,o}\right)/c_{i,o}\\
\theta_\omega &= \omega t_o\\
\theta_e &= \theta_o - \theta_\omega - \theta_s\\
\alpha_{b,o} &= \frac{\pi}{2} - \gamma_{b,o}\\
w_{i,o} &= \left(c_{i,o}^2 + u_i^2 - 2u_i c_{i,o}^2 \alpha_{b,o}\right)^{1/2}\\
f &= \frac{\theta_e r_i}{s_t}
\end{aligned}$$

The width of outcoming jet at internal blade edge is related by the continuity equation to the jet width at runner entrance, s_i

$$s_t = s_i \, \frac{w_i}{w_{i,o}} \; ;$$

and as

$$s_i = \frac{s}{\cos(\beta_i - \alpha_i)} \quad ; \quad \cos(\beta_i - \alpha_i) = \frac{c_i - u\cos\alpha_i}{w_i}$$

it will be:

$$\begin{aligned} s_t &= s\frac{c_i}{w_{i,o}} \Big/ \frac{1 - v\cos\alpha_i}{1 + v^2 - 2v\cos\alpha_i} \\ f &= \vartheta_s \, \frac{r_i}{s} \, \frac{w_{i,o}}{c_i} \, \frac{1 - v\cos\alpha_i}{1 + v^2 - 2v\cos\alpha_i} \end{aligned}$$

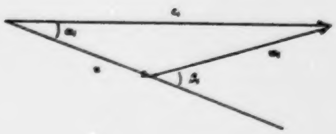

Fig. A.1

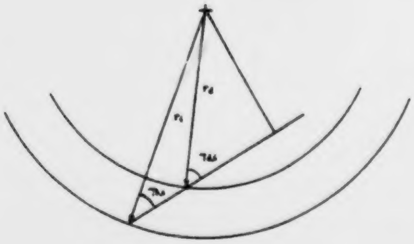

Fig. A.2

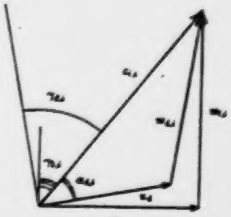

Fig. A.3

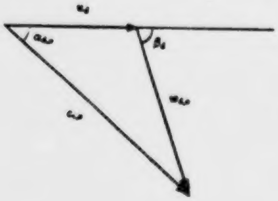

Fig. A.4

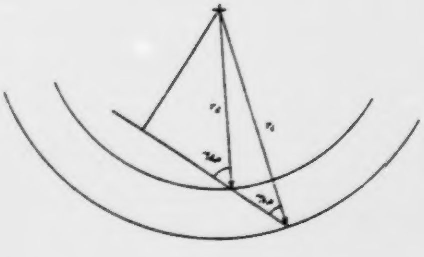

Fig. A.5

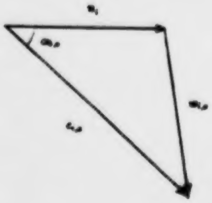

Fig. A.6

Design of Structures for Low Head Open Pit Turbines

By
J.R. Scott, R. Kockel

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DESIGN OF STRUCTURES FOR LOW HEAD OPEN PIT TURBINES

J.R. SCOTT * , R.R. KOCKEL **

Abstract:

Over the past several years, hydraulic turbine manufacturers have experienced a greatly increased market demand for the Open Pit type horizontal axial flow turbine which is ideally suited for hydro installations in the very low head range of 4 to 10 m. with runner diameters from 3.5 to 8 m. The Open Pit turbine offers the advantage of a compact high speed generator with easy access for maintenance from the top of the Pit and requires a highly reliable step-up gear box (speed increaser) to match turbine and generator optimum speeds.

Since the basic configuration of components such as Distributors, Discharge Rings, Bearings, Seals and rotating parts are similar to those of S-type or Bulb type units, DBS EW decided to concentrate on relatively new components which are unique to a Pit turbine, i.e. Pit Structure, Anchor Ring, Speed Increaser and its mounting, as subjects for cost improvements. Final design for these components were applied to the Port Dalhousie Generating Station owned by St-Catharines Hydroelectric Commission, a contract for water-to-wire supply and installation of (2) Propeller Pit turbines (runner diameter 4.0 m, 3.75 MW), to be the first of this type in Canada.

Economies in the Pit structure and Anchor Ring must be achieved without compromising the turbine hydraulic performance, the accessibility to machinery inside the Pit, the ability of the structure to resist all imposed forces, including dynamic effects and finally to maintain accurate alignment of the rotating parts.

The paper to be presented will discuss the design and erection of the turbines for Port Dalhousie. This Open Pit design represents a satisfactory first solution for an Open Pit structure with reasonable economy and suitability for heads up to 10 m.

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Paper presented at "Small Hydro '88", An International Conference and Trade Show.

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I Introduction

Over the past several years, small hydro turbine manufacturers have experienced an increased market demand for the open pit type horizontal, axial flow turbine. This type of machine is well suited for installation in the low head range of 4 to 10 m with runner diameters from 4 to 8 m. For higher heads up to 25m and runner diameters less than 4 m, the S-type tubular turbine as shown in Figure 1 is preferred, of which DBSEW has considerable fabrication and operating experience with 95 Mw (24 units) on line or on order. For higher outputs with heads greater then 10 m. and runner diameters more than 4 m, the bulb type direct drive turbine, in which water passes around a large torpedo shaped generator housing, is usually chosen. (see figure 2). Open pit and direct drive bulb units both have a straight through water passage, which offers a better efficiency for runner diameters greater than 4 m, than an S-Turbine, where losses due to the S-shaped draft tube and immersed shaft begin to adversely affect efficiency.

The open pit design was evolved from the direct drive bulb unit, in efforts to overcome some disadvantages of the bulb turbine design:

1) Difficult accessibility of the large diameter generator within the bulb, and rotating parts, resulting in long downtimes for maintenance when required.

2) When using direct drive, in certain applications the unit RPM is higher than the best efficiency RPM of the runner. This is due to the compromise between generator sizing considerations and turbine efficiency considerations. In other words, turbine runner and generator cannot both run at their optimum efficiency RPM's.

3) The large diameter of the generator bulb housing results in large water passage dimensions with relatively high civil works costs. Also, for multiple unit installations, unit centerline spacings are relatively large.

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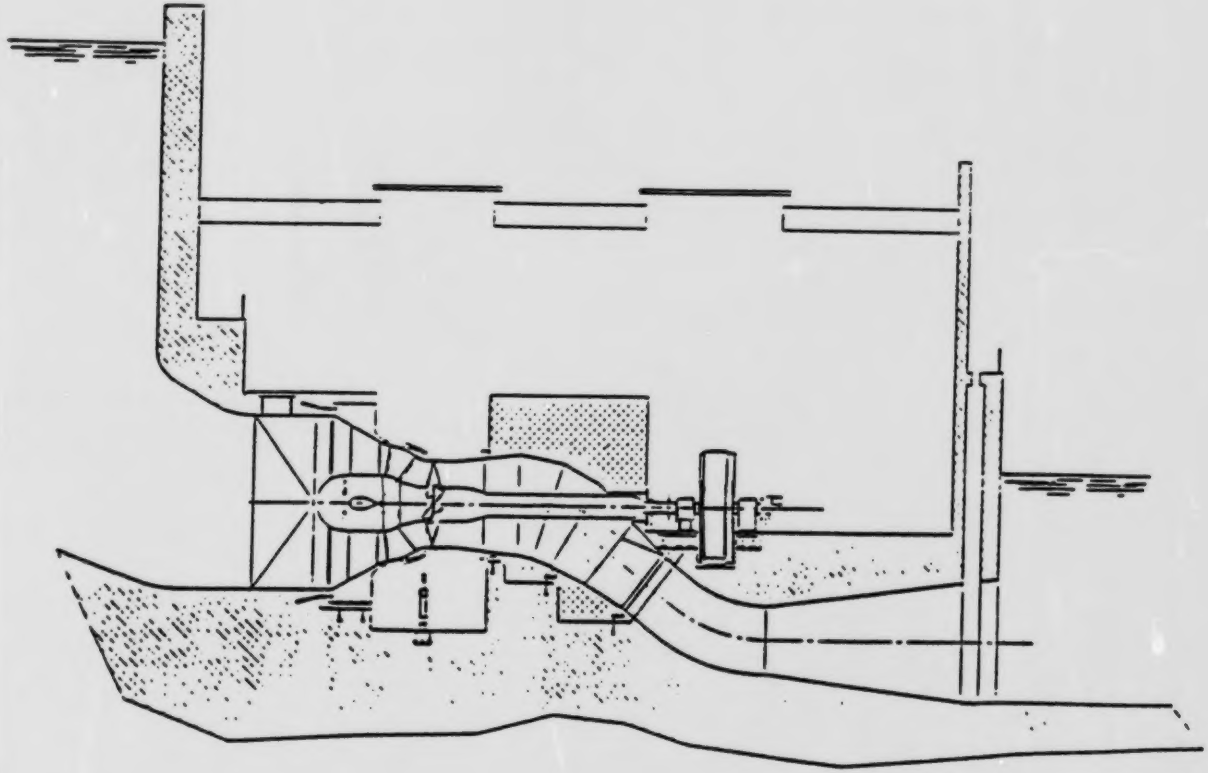
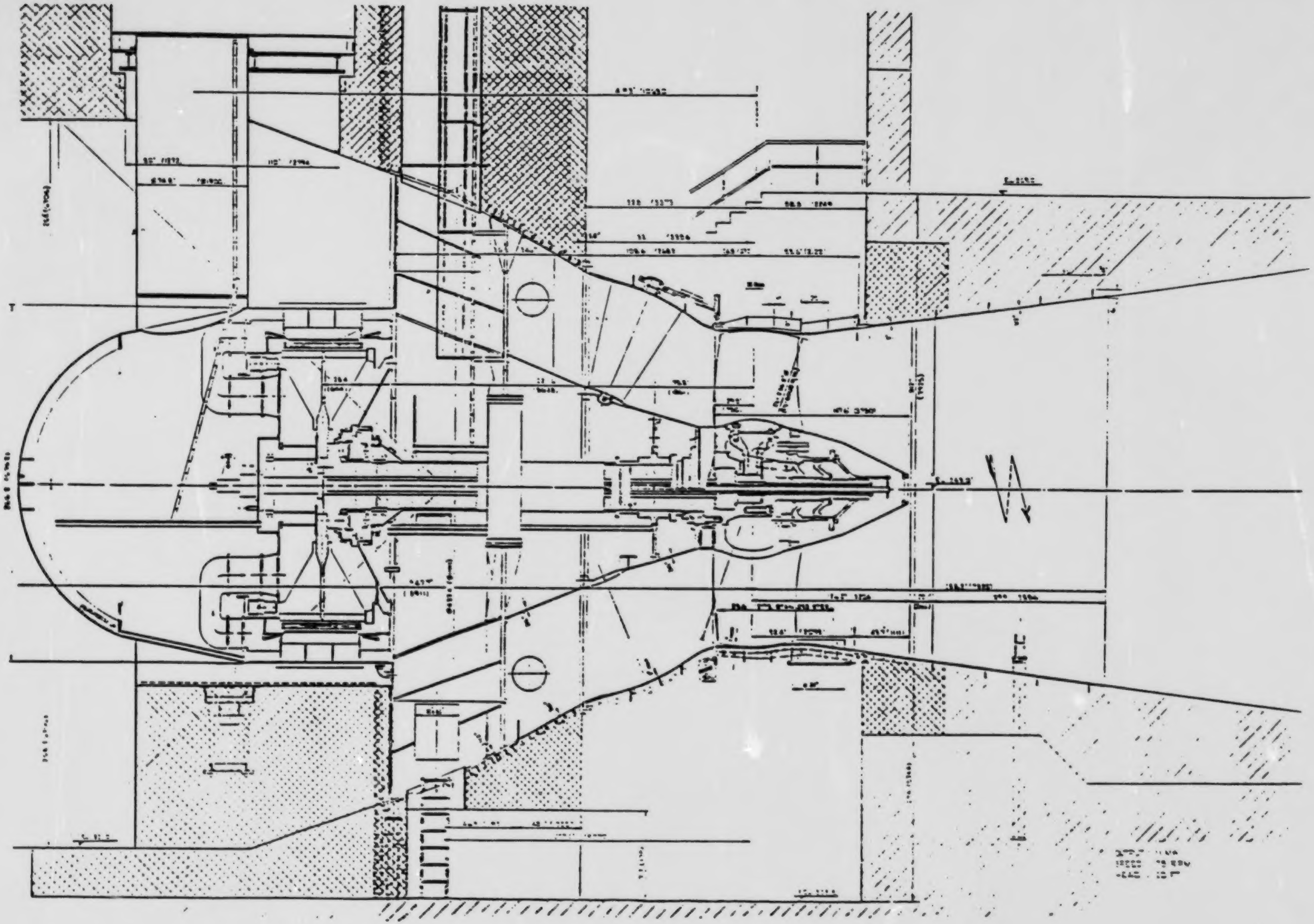


STANDARDIZED S-TURBINES
HEAD: 5 - 25 M
POWER: 1 - 10 M W

FIGURE 1



TYPICAL BULB TURBINE

FIGURE 2

4) Although well suited to resist pressure in the higher head range, the torpedo shaped bulb is expensive to fabricate and a more economical structure could be used for lower heads.

To mitigate these difficulties, a new type of machine was developed with a speed increaser gear box between runner and generator. This enables use of a high speed generator with compact dimensions, and reduced housing size, and allows turbine RPM to be optimized. Overall water passage dimensions can be reduced, and a side benefit is the higher efficiency of a small high speed generator. Therefore the possible higher generator and runner efficiencies will more than offset the efficiency loss due to the interposed speed increaser.

Originally, the first designs for these types of machine were modified bulb designs with small diameter generators, and speed increasers within a smaller diameter torpedo bulb. These units are built today and often are referred to as "gear bulbs". A further design evolution was then to open up the narrow access tube to allow removal of the generator and/or speed increaser, and to have permanent access to all rotating parts. These machines were referred to as "open pit" turbines, but still retained some bulb aspects such as a basically cylindrical generator housing and a spherical torpedo nose. The final design evolution is to reduce costs of the pit or bulb structure by eliminating the bulb derived elements, and making use of flat surfaces and simple, easily fabricated shapes for the open pit structure. This approach is valid for lower heads up to 10 m and represents the true "open pit" turbine design. It is estimated that overall cost of such a unit is approximately 75% of that of an equivalent direct drive bulb unit.

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At DBS ESCHER WYSS, the first applications for the true open pit design are the two 4.0 m runner diameter propeller turbines for Port Dalhousie G.S. in St-Catharines, Ontario.

These units will be the first "open pit" turbines installed in Canada. The main characteristics of the units, as shown in Figure 3 are:

Rated Head:	4.0 m
Rated Output:	3.75 Mw
Turbine RPM:	80 RPM
Generator RPM:	600 RPM
Speed Ratio:	7.5:1

The units are fixed runner blade propeller types rather than double regulated Kaplan types, due to the nearly constant head conditions which prevail for most of the year. Units will run at rated (100%) output for 80% of the time.

II The Pit Structure

The Port Dalhousie pit structure is a steel, self supporting structure which does not depend on the adjacent concrete civil work for supplementary strength. The structure is rigidly attached at its bottom to 2m wide central concrete pier in the water passage, and to the power house floor, about 1m thick, at the top. It is about 3.5 m wide to allow side access within the pit around the generator. Therefore, at the pit structure, the water passage cross section is asymmetrical from top to bottom. The pit structure consists basically of a heavily stiffened horizontal floor, a nose section formed by a vertical semi-cylinder, flat vertical side walls with pressure stiffening, a transverse back wall, and a rear cylindrical section housing the speed increaser. Two concrete filled, steel lined V-section (top and bottom) piers behind the pit and concrete support pier form an acceptable transition from the asymmetric cross section at the pit to the symmetric water passage cross section at the distributor inlet. The pit structure must satisfy the following requirements:

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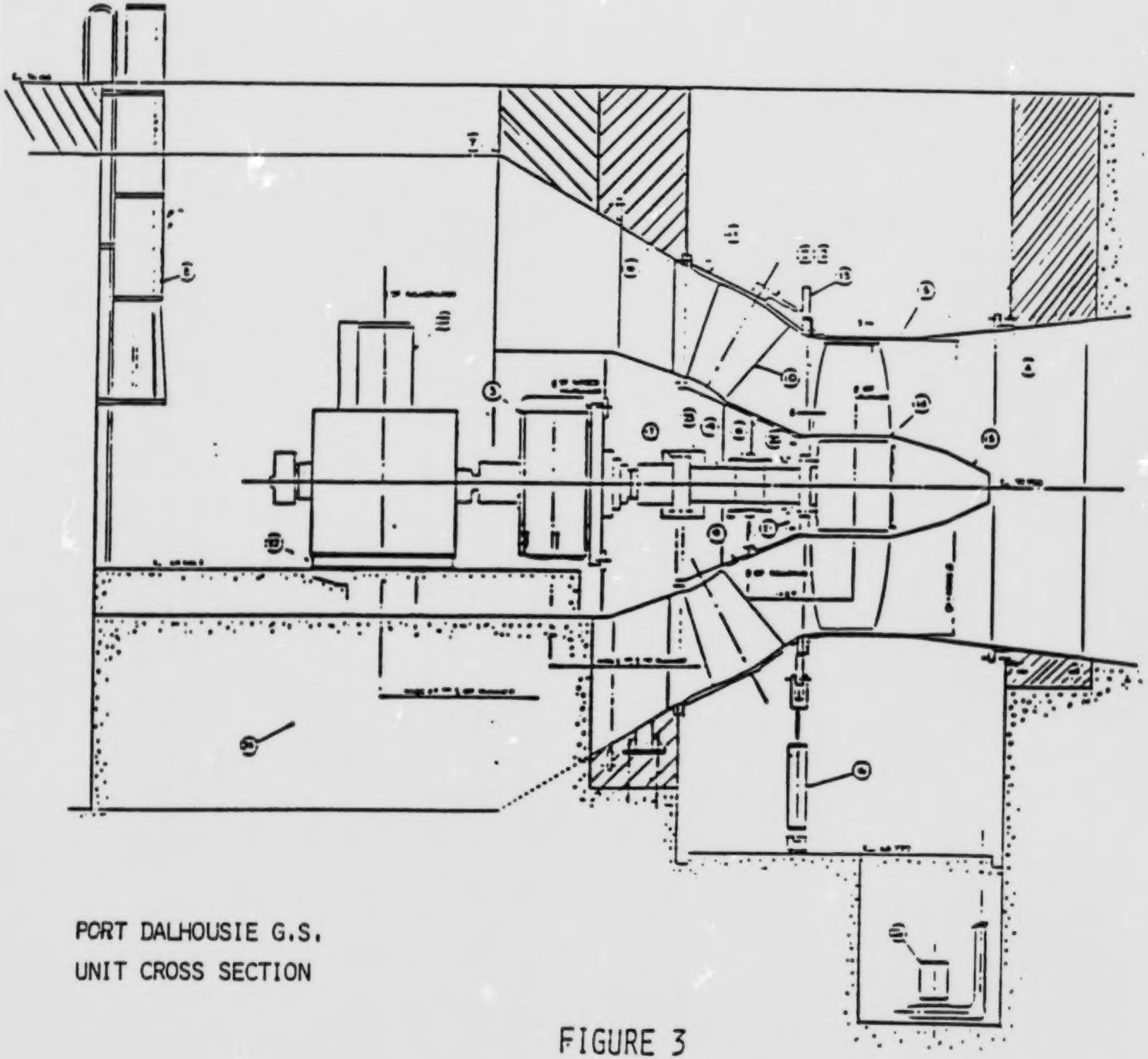

PORT DALHOUSIE G.S.
UNIT CROSS SECTION

FIGURE 3

ITEM	DESCRIPTION
1	TURBINE ASM.
2	SUMP TOWER ASM
3	SPEED INCREASER
4	DRAFT TUBE LINER
5	DISCHARGE RING
6	ANCHOR RING
7	PIT STRUCTURE
8	LADDERS
9	INNER DISTRIBUTOR RING
10	WICKET GATE
11	OUTER DISTRIBUTOR RING
12	DISTRIBUTOR ASM
13	GATE OPERATING RING
14	RUNNER
15	RUNNER CONE
16	SERVOMOTOR ASM
17	COUPLING BOLT
18	GUIDE BEARING
19	TURBINE SHAFT
20	SHAFT SEAL
21	SHAFT SEAL SUPPORT
22	GENERATOR SUPPORT
23	GENERATOR OUTLINE
24	TURBINE FOUNDATION
25	COUPLING GUARD
26	SUMP PUMP

(1) The open pit structure in the water passage must not adversely affect turbine hydraulic efficiency to any significant degree.

(2) The structure must provide good accessibility to machinery such as generator, speed increaser, bearings and seals.

(3) The structure must resist external water pressure and be able to transmit all forces into the concrete supports, without excessive deflection, which would upset alignment of the rotating components.

(4) The structure should be simple and fast to fabricate, to meet cost and schedule requirements.

Viewed from upstream, the pit structure and support pier split the water passage vertically from top to bottom, with the lower portion about 1.5 m narrower than the top, resulting in the asymmetric water passage noted previously. Also, the width transition is abrupt, being formed where the flat pit structure floor overhangs the support pier, which led to some fears regarding the possibility of vortex formation along the overhang. Both pit structure and the support pier have semi circular upstream noses, and the transition from the pit structure and support pier downstream to the distributor inlet is made with the two concrete filled V-section piers noted previously. The downstream piers have an included angle of 56.5^{0}. Since this shape is quite unusual, a model test was run at SEW, Zurich, to determine the affect upon efficiency of this new pit structure shape. An existing bulb turbine model was used, modified to incorporate the Port Dalhousie inlet shape dictated by the new pit structure design. Test results indicated slight efficiency loss compared to a bulb type inlet, which was judged to be acceptable. The model tests also indicates that fairing the pit structure near the bottom where the flat walled section joins the rear cylinder would be effective in preventing vortex formation. The conclusion from the model tests was that the loss in efficiency due to the pit structure shape and the presence of the speed increaser would be offset by the gain in efficiency due to the smaller generator and runner operation at optimum speed, making the new design of pit viable from a generation and economic point of view.

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The pit structure is subjected to a maximum design static head (external) including a small water hammer effect, of 10.5m (15 psi) at floor level, dropping linearly to 3.5m (5 psi) at the top of the structure embedded in the powerhouse floor.

The pit structure floor plate, although connected to the support pier with Nelson studs, is heavily stiffened by plate ribs, and transverse generator support I beams so that it can easily withstand the external pressure with no help from the concrete. The upstream nose of the structure formed of a vertical semi cylinder is of sufficient thickness to withstand external pressure with no stiffeners. The vertical side walls are stiffened with longitudinal T-stiffeners at about 0.9 m spacing. Since the external pressure decreases towards the top, the sections of the stiffeners are reduced progressively from bottom to top, while maintaining constant stiffener spacing. The cylindrical speed increaser housing has sufficient thickness to require no additional circumferential stiffeners apart from the support provided by the main compression ring at its upstream end and the speed increaser mounting at the down stream end. The back wall of the open pit has no stiffeners, but is stayed against infiltration pressure (into the concrete filled V-section) by Nelson studs which connect the skin plate to the concrete of the V-section pier.

Lateral support for the structure against external pressure is provided at the upstream end by a vertical line of transverse I beams which support the upstream edges of the side walls and the open end of the front semi-cylinder. These cross beams are permanent and welded to the skin plates and ends of the side wall T-stiffeners. They are far enough forward in the pit structure to enable the removal of the generator and speed increaser without being removed; therefore both components may be removed without dewatering the unit. Lateral support at the downstream end is given by a massive compression ring located at the junction of the flat walled section and the cylindical speed increaser housing; above this ring, support is provided by the back wall skin plate rigidly attached to the adjacent concrete by Nelson studs as mentioned previously.

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Due to the large displaced volume of the approximately 7.2 m high by 3.5 m wide by 7.2 m long pit structure located inside the water passage, buovancy forces are quite significant. Gross buoyancy is in the order of 250 tons. With weights of steel, equipment, and concrete filled portions of the structure taken into account, the total net buoyancy force to be taken into the main anchorage at the support pier is approximately 180 tons. This large force is taken out into the concrete by six heavy anchor bolts in 3 pairs running through the support pier and nearly down to bedrock level. The anchor bolts terminate in heavy embedded anchor plates, and at their top ends, each pair of bolt chair plates are carried by a pair of heavy transverse plate ribs, welded to the floor skin plate and at their ends to the side wall skin plates. Thus buoyancy forces from the walls and floor are efficiently transmitted to the anchor bolts. The floor region of the pit is therefore massive and very stiff; this stiffness is further increased by pouring concrete into the pit up to the generator base after field erection of the pit. The main anchor bolts are pre-stressed sufficiently to ensure that the concrete of the support pier always remains in compression against tensile forces due to buoyancy and other loadings. To further improve the connection between pier and pit structure floor, the floor plate is provided with Nelson studs, to be embedded in the concrete grout.

The remainder of the forces to be carried by the pit structure are more conventional, and are similar to those occurring in other types of turbines. The magnitudes of these forces are quite low for the size of machine due to the very low head. All forces must ultimately be taken out through the main anchorage at the support pier, or at the top anchorage where the open pit steel liner is anchored to the powerhouse floor with the aid of Nelson studs. Of the two anchorages the bottom (main) anchor is by far the more stiff and this carries most of the imposed loadings.

Longitudinal hydrodynamic thrust on the pit structure during operation (due to static pressure drop along the pit due to increasing flow velocity) is taken mainly at the bottom anchor, and partially at the top, since pit structure stiffness is greatest near the bottom.

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Runner thrust from the runner is taken into the structure at the speed increaser mounting, since the unit thrust bearing is located inside the speed increaser. From the speed increaser mounting flange, the longitudnal thrust is transmitted forward into the pit structure 'box' by seven longitudnal ribs which are welded to the rear cylinder and to the main compression ring at their upstream ends. Once into the box section, the thrust is taken out mainly at the bottom anchorage. Speed increaser reaction torque is taken from the mounting flange into the rear cylinder via the shear ribs welded between the mounting flange and the inner surface of the cylinder. Torque then enters the 'box' section via the junction of cylinder and box section, and is taken out of the structure by a lateral force couple acting at the top and bottom anchorages. (The stiffening effect of the concrete filled, steel lined V pier over the cylindrical section aids in the ability of the top anchorage to help carry torque reactions).

Since the speed increaser also contains the upstream guide bearing for the low speed shaft, radial forces arising from the overhung runner weight and runner dynamic effects are also transmitted through the speed increaser mount and into the pit structure, to be taken out at the top and bottom anchorages.

Longitudnal and tangential forces from the inner wicket gate bearings are transmitted from the inner distributor ring, through the bolted joint into the anchor ring inner cone, and thence through the field welded joint into the pit structure rear cylinder. They are taken out at the pit structure anchorages in the same way as runner thrust and speed increaser torque reaction.

The generator inside the open pit has its base bolted to a support frame which is welded to two large transverse I-beams. These beams are in turn welded to the pit structure floor plate and the side wall skin plate at their ends. Since the pit structure bottom will be concrete filled up to the tops of the generator support I-beams, the generator thus has a very stiff and rigid mounting. Generator full load reaction torque is thus transmitted as a vertical force couple into the bottom main anchorage. The generator mounting is also designed to take the generator short circuit condition in which generator torque can be as high as 14 times the full load torque.

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III The Anchor Ring

The anchor ring assembly serves as the anchorage for the outer distributor and provides the connection between the inner distributor and the rear end of the pit structure. Although superficially similar to the stay ring of an S-turbine or bulb turbine, it can be seen immediately that it is of much lighter construction than a typical stay ring. This is because, while a stay ring must rigidly connect the inner and outer distribuors to a single anchorage region on the outside of the water passage, and thus carry all machine forces into concrete, the pit turbine anchor ring does not have to rigidly connect the inner and outer parts of the unit. Inner distributor forces pass through the anchor ring inner cone into the pit structure rear cylinder and thence to the pit structure anchorages. The only anchorage function provided by the anchor ring is to transmit longtitudnal and tangential forces from the outer wicket gate bearings directly into concrete on the outside of the water passage via the anchor ring outer shell, stiffening ribs, and anchor bolts. Therefore in service, there is no need for a physical connection between the inner and outer cones of the anchor ring. V-section radial ribs form the back ends of the concrete V-piers, while the radial plate vanes serve to stiffen the unit when it is in use as an assembly and alignment jig for the shop erection of the distributor assembly. These plate vanes are removed to reduce hydraulic losses after erection of the unit. The anchor ring is flexible to the extent that additional bracing of the inner and outer portions of the assembled distributor is required for shipment even with the anchor ring assembly bolted to the distributor.

IV The Speed Increaser

The speed increaser is of the (epicyclic gear type), and thus has co-axial turbine and generator shafts. It is manufactured by Philadelphia Gear Inc.

The single stage gear drive is a planetary arrangement enclosed in a fabricated steel casing, using a fixed annulus and multiple planet gears rotating on babbitted spindles.

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The speed increaser is provided with a combined thrust and guide bearing of the roller type also designed to accept the reversal thrust from the turbine.

All rotating parts are designed to withstand safely the maximum runaway speed of the turbine which is almost 3 times the rated speed. The gear case housing is flange mounted to the pit structure; all loads from the runner are transmitted uniformly to the pit structure and finally taken by the foundation anchors. The flange mounting was chosen in preference to a foot mounting in order to avoid concentration of loading at the downstream end of the support pier. The low speed shaft of the speed increaser is rigidly connected to the turbine shaft with a friction coupling while the high speed shaft, is connected to the generator shaft with a flexible gear coupling which allows the internal rotating parts of the speed increaser (i.e. sun, pinion and planets) to float freely and equally distribute the loads. The lubrication of the speed increaser is done by a remote oil pumping unit located on the turbine floor; the unit also provides the lubricating oil for the generator and turbine guide bearings.

Since reliability of the unit is critical, it has been designed for a 30 year life.

V Description of Other Major Components

Distributor Assembly:

The assembly includes the inner and outer distributor rings, 16 wicket gates and an operating mechanism.

The wicket gates are of cast steel, are moved by the operating ring which is connected to one single acting servomotor anchored in the powerhouse floor. The closure of the wicket gate is done by a counter weight. All wicket gates bearings are self lubricated; therefore the water will not be contaminated by oil. Buckling rods provide the connection between each wicket gate and the gate operating ring.

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The inner cone is provided with flanges for attachment to the inner cone of the anchor ring and will also support the downstream turbine guide bearing as well as the shaft seal. Adequate access is provided inside the cone for inspection and maintenance of the turbine guide bearing and shaft seal.

Discharge Ring:

The discharge ring is of welded steel construction with a stainless steel portion upstream and downstream the centerline of the runner. The assembly is split along the horizontal turbine axis and the upper portion is removable for major maintenance of the runner. Also an adjustable joint is provided between the discharge ring and the draft tube.

Runner:

The runner has four stainless steel (chromium-nickel 13-4) cast blades welded to a cast steel cylindrical hub. Each blade is accuratedly machined by a 5 axis CNC machine and rigorously checked dimensionally by the theodolite method.

Shaft Seal:

The shaft seal includes two carbon fibre sealing rings, which seal radially against a stainless steel shaft sleeve and axially against the internal faces of the seal chamber.

An inflatable seal is provided in order to inspect or replace the sealing elements without dewatering the unit.

Downstream Turbine Guide Bearing:

The guide bearing is of the babbitt lined shell type, with forced lubrication and is split horizontally into two sections. The bearing support is rigidly bolted to the inner distributor cone. The guide bearing is provided with a high pressure oil supply in order to lift the shaft before start up of the unit.

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VI Shop Assemblies and Site Erection

In order to meet the schedule requirements and speed up the erection at site, all major components are assembled in the shop prior to shipment.

Shop assembly and erection sequence is the following:

The first components to be fully assembled are the pit structures and anchor rings. The pit structure is then sent, via barge and road, to site, unloaded and put in its final position by a 400T mobile hydraulic crane. The structure is then levelled, aligned and securely bolted to the foundation anchors. The concreting of the water passage around the pit structure is then completed. (See Figures 4 & 5)

The draft tube is the second major component to be installed and anchored into the first stage concrete.

The anchor ring is used as a supporting structure for the shop assembly of the distributor and operating mechanism. After all wicket gates are accurately adjusted and the gaps between gates and inner/outer rings are checked the full assembly is loaded into a barge and shipped to site. The full assembly is then put in its position by using the same crane as handles the pit structure, as shown in Figure 6.

After levelling and alignment is completed, the inner cone of the anchor ring is welded to the pit structure and the concreting aroung the outer ring of the anchor ring is completed. Then the turbine shaft is introduced and temporarily supported inside the inner cone and the lower portion of the guide bearing is installed. Then the turbine shaft is lowered onto the guide bearing and temporarily aligned; the upper portion of the guide bearing is then installed.

The speed increaser is then lowered inside the pit, slid to its final position, aligned and finally bolted to the flange of the pit structure. The low speed shaft of the speed increaser
is then coupled to the turbine shaft. After installing the lower part of the discharge ring the runner is lowered and coupled to the turbine shaft and finally the shaft seal is installed. All rotating components downstream the speed increaser are then finally aligned. The generator is the last major component to be installed in the pit structure.

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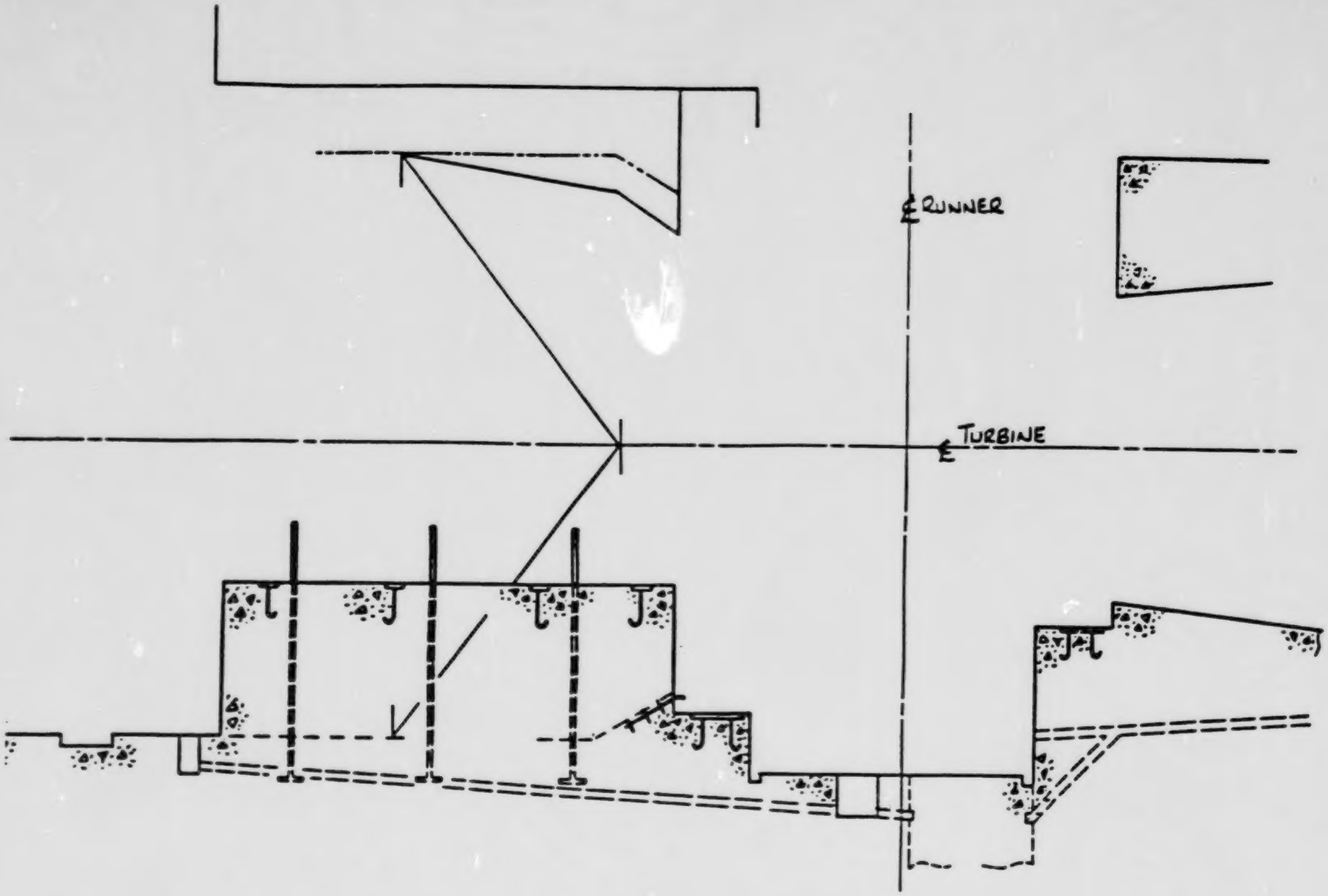
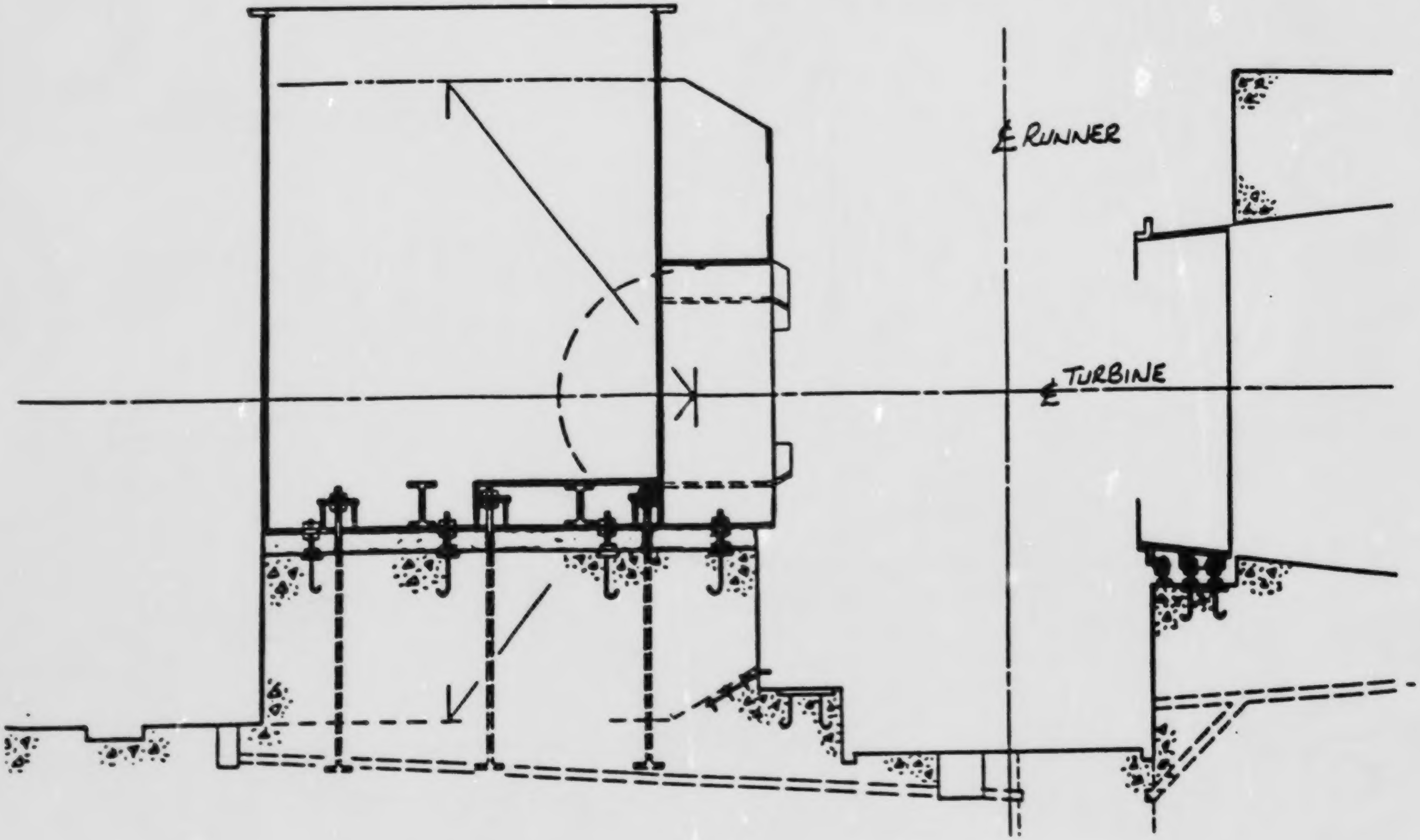

℄ RUNNER
℄ TURBINE

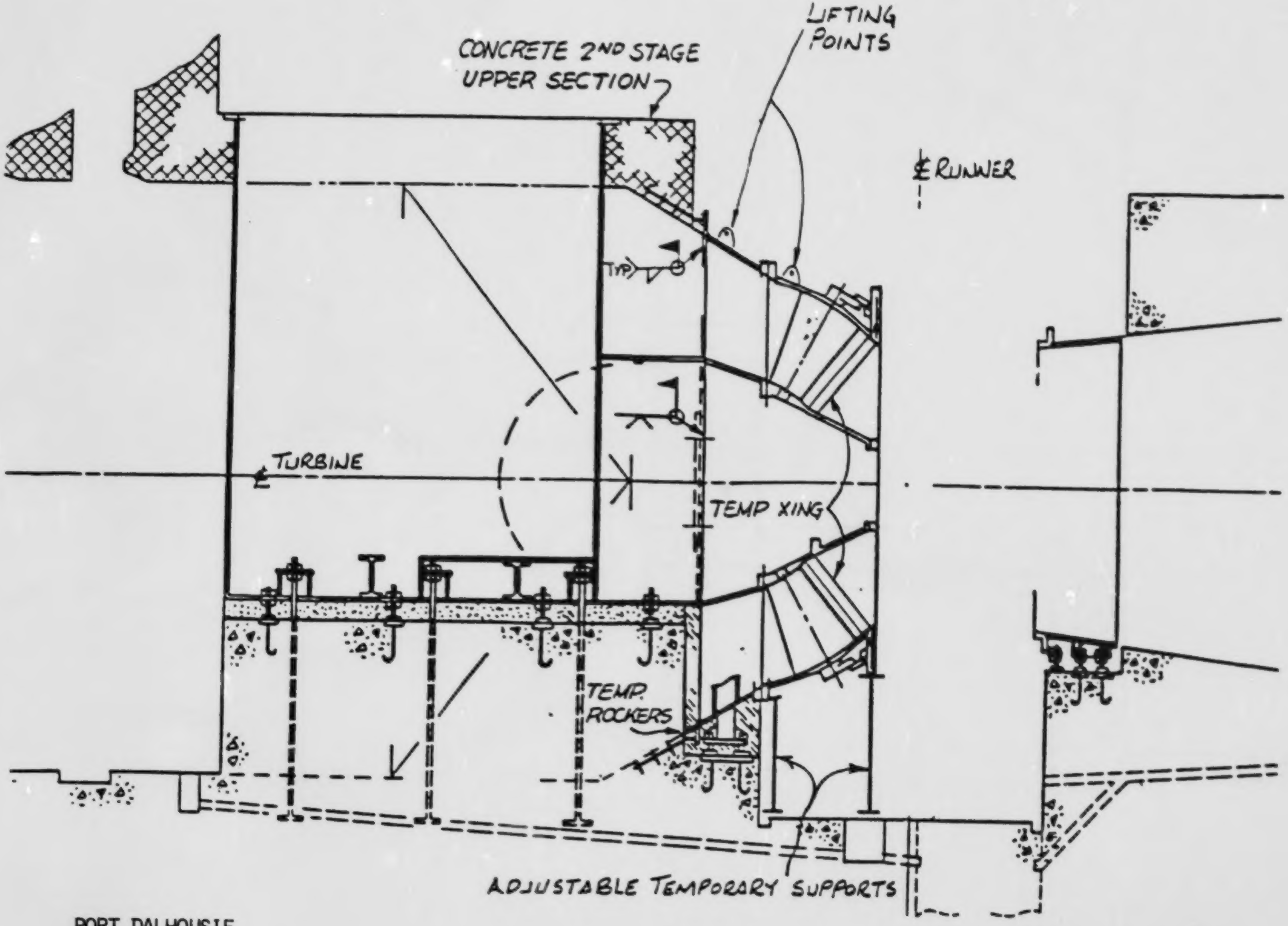
PORT DALHOUSIE G.S.
ERECTION SEQUENCE

FIGURE 4


℄ RUNNER
℄ TURBINE

PORT DALHOUSIE G.S.
ERECTION SEQUENCE

FIGURE 5


CONCRETE 2ND STAGE
UPPER SECTION
LIFTING
POINTS
℄ RUNNER
TYP
℄ TURBINE
TEMP XING
TEMP
ROCKERS
ADJUSTABLE TEMPORARY SUPPORTS

PORT DALHOUSIE
ERECTION SEQUENCE

FIGURE 6

Conclusion

The authors expect that the Port Dalhousie open pit turbines will perform as intended, with full satisfaction to the owner. DBS Escher Wyss hopes to have future opportunities to further explore and refine the open pit turbine concept.

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JS1/MS

A Study on the Hydraulic Performance Characteristics of Cross Flow Turbine (CFT): Analysis and Experiments

By
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A Study on the Hydraulic Performance Characteristics of Cross Flow Turbine : Analysis and Experiments

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Abstract

In the study the characteristic equations for the prediction of hydraulic performance of cross flow turbine(CFT) are formulated with considering important real flow behavior. The tangential flow to the rotating runner and the flow deviation angle in blade passages are considered in the hydraulic efficiency. Also, the geometric parameters such as nozzle angle, entry arc angle, aspect ratio of runner, etc. are included in the characteristic equations.

To test the analytical model performance, experimental model tests have been conducted. The model turbine is designed to be the aspect ratio of 0.4, runner diameter of 0.35m, number of 24 blades, entry arc angle of 120 degree and radius ratio of 0.66. The maximum hydraulic efficiency is shown to be 62% from model test and 65% from calculation. The hydraulic performance characteristics from formulated equations and experiments have shown excellent agreement.

In the present study, the hydraulic performance characteristic equations for the unit rotational speed, flow rate, torque and specific speed are developed. Also the design equations for velocity ratio, blade angle and radius ratio, which are very important parameters in practical design, are derived. Based on the results from model tests,it has been found that the nozzle flow coefficient is not constant but decreased with increasing the velocity ratio. And the reduction of the tangential flow obtained by installing a shroud at the nozzle edge is effective to improve the hydraulic performance. In the study the visual flow patterns in CFT are also presented.

Nomenclature

A : Arc angle
C : Nozzle flow coefficient
c : Chord length of blade
D : Diameter of runner
g : Gravity

$\star$: Aspect ratio
α : Absolute flow angle
β : Relative flow angle
β^* : Blade angle
β_s : Stagger angle

H : Head
i : Incidence angle
K : Radius ratio
L : Length of runner
N : Rotational speed
N_s : Specific speed
P : Power
Q : Flow rate
R : Degree of reaction
s : Arc length
T : Torque
t : Thickness of blade
U : Peripheral speed
V : Absolute velocity
W : Relative velocity

γ : Specific gravity
δ : Deviation angle
ϵ : Utility factor
η_h : Hydraulic efficiency
θ : Camber angle
κ : Incidence factor
ρ : Density
σ : Solidity
ϕ : Velocity ratio
χ : Flow rate ratio

Superscripts;

$*$: Designed

Subscripts;

$_{1234}$: Station number
$_{1t}$: Tangential flow at 1st stage
$_{1c}$: Cross flow at 1st stage
$_{2c}$: Cross flow at 2nd stage
$_{11}$: Unit value of hydraulic performance
$_{\theta}$: Tangential flow
$_{i}$: Inner
$_{id}$: Ideal flow with no flow loss
$_{m}$: Meridional
$_{o}$: Outer
$_{T}$: Total
$_{shaft}$: Shaft

1. Introduction

Due to its inherent advantages in low cost manufacturing and stable operating performances for the wide range of flow rate, cross flow turbine(CFT) is recently getting more attention for small hydro power plant application.

CFT, as an impulse turbine, has two major parts of the nozzle and the runner. It is known that, in this turbine design, proper consideration of the geometric design parameters, such as nozzle wall shape, nozzle angle, entry arc angle, guide vane shape, runner diameter, number of blades, blade angle, radius ratio, and aspect ratio of the runner is important. These parameters govern the flows passing through CFT and the hydraulic performance of CFT is affected by these.

Owing to the above complexity of internal flows in CFT, a more realistic hydraulic efficiency equation considering the flow loss mechanism has not been presented up to now.

In the results from classical studies[1-3] the hydraulic efficiency were expressed without considering the nature of real flows in CFT. But in the later studies, the effects of the nozzle shape and entry arc angle[4,5], blade forces[6], optimal number of blades and blade angle[7,8], aspect ratio of runner[9,10] have been investigated. These studies, however, have not sufficiently provided actual design data considering overall real flow phenomena in various types of cross flow turbine.

In the present study, through analytical and experimental works, it is intended to present a prediction model of the CFT's hydraulic performance characteristics. In the process of performance analysis to formulate the characteristic equations, the tangential flows releasing directly from the rotating runner blades at the first stage are considered. Additionaly, the flow losses in blade passages are included as a flow deviation angle instead of an arbitrary loss coefficient in the previous cases presented.

To justify and test the analytical results obtained from using correlations on the flow deviation angles, the ratio of tangential flow rate and the variation of nozzle flow coefficient, the experimental model tests are carried out and later both results from calculation and experiments are examined.

2. Analysis

2-1. Flows in Cross Flow Turbine

The flows in the runner can be divided into the cross flow and the tangential flow as in Fig.1. The cross flow has two stages for passing through the runner. In the first stage, the major portion of the energy transfer occurs. Sonnek[2] and D.G.Shephered[11] had described that the transfered energy in the first stage is approximately three quarters of the available total energy. In their brief analyses, the tangential flow had been ignored and the cross flow had been simply assumed to be ideal fluid flows. However, to obtain the effective energy transfered actually in a CFT, the tangential flow and the flow losses in the flow should be considered in the performance analysis.

To start the analysis, we may have the radius ratio as a designed geometric condition and the velocity ratio as an operating condition as shown in Eqns.(1) and (2) respectively. Considering the ratio of the tangential flow rate to total flow rate as in Eqn.(3), the power which is transfered by the tangential flow can be written as Eqn.(4).

$$K \equiv \frac{r_i}{r_o} \qquad (1)$$

$$\phi \equiv \frac{U_1}{V_1} \qquad (2)$$

$$\chi \equiv \frac{Q_e}{Q_T} \qquad (3)$$

$$P_{1t} = \chi \cdot \frac{V_1^2}{g} \cdot \phi \cdot \{\cos\alpha_1 - \phi(1-\chi)\} \qquad (4)$$

$$i_1 = \left(\frac{\pi}{2} - \beta^*\right) - \tan^{-1}(\cos\alpha_1 - \phi\,\mathrm{cosec}\,\alpha_1) \qquad (5)$$

For the cross flow at the first stage, the inlet flow has an incidence angle represented as Eqn.(5). And the exit flow has some flow losses created in blade passages. Here, it can be understood that the flow losses in blade passages are closely related to the incidence angle and blade geometry as occurs in a two-dimensional cascade flow. Hence the flow losses can be classified into the incidence loss and the blade profile loss. O.E.Baje[12] has considered only the incidence loss with impulse theorem, in which the loss was presented as the change of relative inlet flow velocity and its direction.

However, in order to express the flow losses including the profile loss, it is appropriate to present the flow deviation angle as a function of blade geometry and incidence angle, which is used generally in analyzing the off-design performance of a 2-D linear cascade flow. The flow deviation angle due to flow separations on the surface of blades causes changing of relative velocity and its direction at the exit as shown in Fig.2. It can be seen that an increment of flow deviation angle reduces the rate of momentum transfer. Therefore, the effective energy transfered and the energy losses at the first stage of cross flow can be presented in terms of the flow deviation angle as shown in Eqns.(6) and (7) respectively.

$$P_{1c} = (1-\chi) \cdot \frac{V_1^2}{g} \cdot (\phi\cos\alpha_1 - K^2\phi^2 - \phi\sin\alpha_1\tan\delta_1) \qquad (6)$$

$$H_{L1} = \frac{\Delta W_{U2}^2}{2g} = \frac{V_1^2}{g}(\phi\sin\alpha_1\tan\delta_1) \qquad (7)$$

The flow between the first and the second stage also contains the losses caused by the viscous friction and turbulence. So the loss mechanism of this flow may be expressed with the viscous friction and turbulent shear stress. Moreover, when air bubbles are formed at the tail of blades, the flow becomes a two-phase state that can not be simply explained. But in this study, these losses are neglected because the magnitude of these losses is so small when comparing with the impulse-momentum losses at both two stages. Based on the velocity diagram of exit flow at the first stage as in Fig.3, the inflow conditions at the second stage can be assumed as Eqn.(8). As in the first stage, the energy transfered in the second stage is also written as Eqn.(9). The absolute flow angles at the inlet and exit in the stage can be written as Eqns.(10) and (11) respectively.

$$\left.\begin{aligned} V_3 &= V_2 \\ \alpha_3 &= \alpha_2 \quad , \qquad i_2 = \delta_1 \\ W_3 &= W_2 \end{aligned}\right\} \tag{8}$$

$$P_{2c} = (1-\chi)\cdot\frac{V_1^2}{g}\cdot\left\{\phi \sin\alpha_1 (\cos\alpha_3 - \tan\alpha_4)\right\} \tag{9}$$

$$\alpha_3 = \cot^{-1}(K^2\phi \operatorname{cosec}\alpha_1 + \tan\delta_1) \tag{10}$$

$$\alpha_4 = \tan^{-1}\left\{\phi \operatorname{cosec}\alpha_1 - \cot(\beta^* + \delta_2)\right\} \tag{11}$$

2-2. Design Equations

For the cross flow of no losses, the utility factor[11] can be defined as Eqn.(12). By differentiating this utility factor with respect to the velocity ratio and by equating to zero, we may have the design velocity ratio as shown in Eqn.(13).

From Fig.2, the correlation between the blade angle and the velocity ratio is written as Eqn.(14). For a constant nozzle angle of CFT, if the incidence angle is zero at the design velocity ratio, the design blade angle becomes as Eqn.(15) by substituting the Eqn.(13) into the Eqn.(14).

From the concept of the degree of reaction as defined in Eqn.(16)[11], the degree of reaction is becomming zero when it is assumed that all of the effective energy transfered at a design velocity ratio are obtained by the impulse-momentum transfer without flow losses (i.e., no flow deviation angles). Hence, by substituting the velocity components into the Eqn.(16) and then equating to zero, the Eqn.(17) can be rewritten as functions of radius ratio, velocity coefficient and nozzle angle. The design radius ratio can be presented as Eqn.(18).

$$\varepsilon \equiv \frac{(P_{1c} + P_{2c})_{id}}{(P_{1c} + P_{2c})_{id} + \left(\frac{V_4^2}{2g}\right)} \qquad (12)$$

$$\phi^* = \frac{\cos\alpha_1}{2} \qquad (13)$$

$$\cot\beta^* = \left(\frac{\cos\alpha_1 - \phi}{\sin\alpha_1}\right) \qquad (14)$$

$$\beta^* = \tan^{-1}(2\tan\alpha_1) \qquad (15)$$

$$R \equiv \frac{(W_2^2 - W_1^2) + (U_1^2 - U_2^2)}{(V_1^2 - V_2^2) + (W_2^2 - W_1^2) + (U_1^2 - U_2^2)} \qquad (16)$$

$$R = \frac{1}{K^2}\cdot\sin^2\alpha_1 + 2\phi\cos\alpha_1 - K^2\phi^2 - 1 = 0 \qquad (17)$$

$$K^* = \left\{-2\tan^2\alpha_1 + 2\tan\alpha_1\left(\tan^2\alpha_1 + 1\right)^{1/2}\right\}^{1/2} \qquad (18)$$

2-3. Characteristic Equations

The absolute velocity of inlet flow at the first stage may be written as Eqn.(19) from the general definition of nozzle flow coefficient. Since Eqn.(20) is the total energy transfered, the hydraulic efficiency can be presented as Eqn.(21) with considering the nozzle angle, blade angle, radius ratio, flow deviation angle, tangential flow rate ratio and nozzle flow coefficient.

Generally the performance of the turbine can be determined by applying the characteristic equations of Eqn.(22) using the parameters such as the specific speed, the flow rate, etc. To obtain the characteristics from Eqn.(22), we need the experimental data from model tests. However, by correlating Eqn.(21) and the relevant geometry of the turbine with Eqn.(22), we also can have the turbine performance from the characteristic equations of Eqn.(23) directly.

$$V_1 = C\cdot\sqrt{2gH_T} = \frac{\pi\cdot D\cdot N}{60\cdot\phi} \qquad (19)$$

$$P_{shaft} = P_{1t} + P_{1c} + P_{2c} \tag{20}$$

$$\begin{aligned}\eta_h = 2C^2\{&\chi\cdot\phi[\cos\alpha_1 - \phi(1-\chi)] \\ &+(1-\chi)\cdot(\phi\cos\alpha_1 - K^2\phi^2 - \phi\sin\alpha_1\tan\delta_1) \\ &+(1-\chi)\cdot[\phi\sin\alpha_1(\cot\alpha_3 - \tan\alpha_4)]\}\end{aligned} \tag{21}$$

$$\left.\begin{aligned}&N_{11} \equiv \frac{D\cdot N}{\sqrt{H_T}}, \quad Q_{11} \equiv \frac{Q_T}{D^2\cdot\sqrt{H_T}}, \\ &P_{11} \equiv \frac{P_{shaft}}{D^2 H_T\sqrt{H_T}}, \quad T_{11} \equiv \frac{T}{D^3 H_T}, \quad N_s \equiv P_{11}^{1/2}\cdot N_{11}\end{aligned}\right\} \tag{22}$$

$$\begin{aligned}N_{11} &= \frac{60\cdot\phi\cdot C}{\pi}\cdot\sqrt{2g} \\ Q_{11} &= \frac{1}{2}\cdot A_T\cdot C\cdot\sin\alpha_1\cdot\sqrt{2g}\cdot\mathcal{A} \\ P_{11} &= \frac{\sqrt{2}}{2}\cdot\rho\cdot g^{3/2}\cdot C\cdot\eta_h\cdot A_T\cdot\sin\alpha_1\cdot\mathcal{A} \\ T_{11} &= \frac{1}{4\phi}\cdot\rho\cdot g^2\cdot\eta_h\cdot A_T\cdot\sin\alpha_1\cdot\mathcal{A} \\ N_s &= \left\{\sqrt{2}\cdot\rho\cdot\left(\frac{C}{\pi}\right)^3\cdot\eta_h\cdot A_T\cdot\sin\alpha_1\cdot\mathcal{A}\right\}^{1/2}\cdot 60\cdot\phi\cdot g^{5/4}\end{aligned} \tag{23}$$

3. Experiments

3-1. Test Facilities

In the experiments two different types of cross flow turbine, CFT1 and CFT2, were used. Both model CFT1 and CFT2 are low head type turbines having 120 deg. of the nozzle entry arc angle, the nozzle angle of 15 degree, the aspect ratio of 0.4, the number of blades of 24, the runner diameter of 0.35m, the radius ratio of 0.66, the blade angle of 30 degree, the camber angle of blade of 75 degree. Runner blades are made of the stainless steel pipe of 120mm diameter. To observe the flows passing through the runner, the frontal panel of the turbine was made of 15mm thickness see-through plexiglass. A sketch of test facility is drawn in Fig.4. The set-up of the model CFT is shown in Fig.5.

3-2. Instrumentation and Measurements

Head and flow rate were obtained in the form of electric signals by means of differential pressure transducers and flow sensor. Torque and rotational speed were detected by the torque-tacho meter connected to the shafts between CFT and load. A generator with gear box was used as a variable speed electric load. An arbitrary rotational speed was obtained by the load controller having the field current adjuster. For a rapid and accurate data processing, the data acquistion system shown in Fig.5 was used.

Test conditions of water head for CFT1 and CFT2 were 3.07m, 2.97m, respectively. Fluctuations of the test heads were maintained within 0.045%, 0.02% of the standard deviation for CFT1 and CFT2. The rotational speed was varied from 90 r.p.m. to 340 r.p.m. during the tests. The openning rate of guide vane was varied in six steps. Since the aspect ratio of the model CFTs in this study is 0.4, the measured data are converted into the ones of the CFT having unit aspect ratio. In order to obtain the hydraulic efficiency based on the measured torque, the friction torque at thrust bearings of model CFT is compensated in calculating the shaft power.

4. Results and Discussion

4-1. Effect of Flow Deviation Angle

As the first step to estimate the effect of the real flow on the turbine performance, the effect of the flow deviation angle is examined by using Eqn.(24). In this calculation, the correlation of the off-design performance of 2-D linear cascade flow is applied.

$$\delta_n = \frac{n}{2}\cdot(1-K^2)\cdot \theta/\sigma_n^{\frac{1}{n}} + n\cdot\mu\cdot i_n + (t/10c) \qquad (24)$$

$$\text{where,}\quad \mu = \frac{\beta_s}{(\theta+\beta^*/2)} \quad \text{for } i \geqslant 0,$$

$$\mu = \frac{\beta_s}{(\pi+2\theta+\beta^*)} \quad \text{for } i<0,\quad n = 1 \text{ or } 2$$

The effects of flow deviation angle is presented as the kinetic energy transfer ratio at each stage flow in Fig.6. From the results it can be seen that K.E. transfer at first stage decreases as the velocity ratio increases for both cases with and without flow deviation. But,at the second stage, K.E. transfer increases for the case without flow deviation as velocity ratio increases whileas in the case with flow deviation K.E. transfer decreases as the velocity ratio exceeds 0.45. The reason for these can be explained as the absolute inlet velocity at the second stage increases due to the flow deviation angle at the first stage.

4-2. Nozzle Flow Coefficient and Tangential Flow Rate

The nozzle flow coefficient is an important real flow parameter characterizing the hydraulic performance of CFT. But most of previous studies assumed it as a constant. In addition, the tangential flow rate has not been considered in the hydraulic efficiency except the study done by W.W. Durgin[13]. In the present study these factors are examined by applying Eqns.(25) and (26). The results are shown in Figs.7 and 8.

$$C = \left\{ 1 + \frac{\phi^2}{2}(1-K^2) + 0.05 \right\}^{-\frac{1}{2}} \tag{25}$$

$$\chi = \frac{\phi}{2 \cdot A_T \sin\alpha_1} \cdot (1-K^2) \tag{26}$$

From Fig.7, it is noted that the nozzle flow coefficient affects the hydraulic efficiency strongly. The maximum hydraulic efficiency is shown to be dependent upon the nozzle flow coefficient. From Fig.8 it is presented that the tangential flow rate ratio strongly affects the hydraulic efficiency. It also can be seen that the maximum hydraulic efficiency point varies as the flow rate changes.

4-3. Design Equations

The value of design points, such as radius ratio, velocity ratio and blade angle, are plotted against the nozzle angle in Fig.9. The value are computed from Eqns.(13),(15) and (18). Here, to get the nozzle angle determining the design point, it is required to know the kinetic energy ratio of the exit flow at the second stage at first. Fig.10 presents the variations of kinetic energy ratio for nozzle angle of 10, 15 and 20 deg. From the figure we can see that the minimum integrated area of K.E. ratio occurs at 15 deg. of nozzle angle. Hence it can be said that the optimal nozzle angle is near 15 degree. This confirms why most of all commercialized CFTs are designed as the nozzle angle of 16 deg. and the radius ratio of 0.66. It also justify the method employed in the present study is correct.

4-4. Hydraulic Performance Characteristics

Fig.11 shows the comparisons of nozzle flow coefficient computed from Eqn.(25) and experimental results. The nozzle coefficient of experiments obtained from model CFTs has shown good agreements with analytical results but has trend of rapid decrement as velocity ratio increases than results from Eqn.(25).

Fig.12 illustrates curves of unit flow rate and hydraulic efficiency against the unit rotational speed. From this figure it can be seen that the results from experiments and analysis for unit flow rate quite agrees well. The maximum hydraulic efficiency from analysis is 65% while the ones from experiments of CFT1 and CFT2 are 62% and 72% respectively.

The hydraulic efficiency of CFT1 has shown more rapid decrement than the one from analysis when the unit speed is over 50. From Fig.8, it should be noted that the hydraulic efficiency of CFT2 is better than the one of CFT1. The improvement of this has been obtained from the reduction of tangential flows by installing extended shroud.

Fig.13 shows that the unit torque from both results of experiment and analysis have good agreement. In the figure it can be seen that the unit shaft power has similar variation trends with the hydraulic efficiency against unit speed.

The specific speed is plotted against the unit rotational speed in Fig.14. For the model CFTs having 24 blades the optimal design specific speed and unit rotational speed is near 110 Kw-m and 42, respectively. In the figure we can see that CFT2 has more wide range of the rotational speed where significant power deterioration is not expected.

4-5. Openning Rate of Guide Vane

In Fig.15 the unit flow rate is plotted against guide vane openning rate for CFT1 and CFT2. It can be seen in the figure that due to leakage flow in model CFT the unit flow rate doesn't become zero even when guide vane position is completely closed. From Fig.16 and 17, it has been found that the unit rotational speed and shaft power decreases almost linearly with decreasing the openning rate. Therefore it is able to predict that the governor system for these CFTs would be acceptable for controlling the guide vane.

4-6. Flow Visualization

Fig.18 shows the observed flow patterns for CFT1 and CFT2 in the present study. From the figures we can see that the position of the second stage flows moves toward the edge of nozzle and the tangential flow rate decreases as the rotational speed increases. By installing extended shroud in CFT2 the arc angle between second flow position and nozzle edge became about half of the one of CFT1. Correspondingly we can see that the tangential flow rate of CFT2 reduces according to the decrement of arc angle. In the figure it can be observed that the cross flows between two stages are crashed into the shaft for rotational speed less than 240 R.P.M., which is undesirable flow patterns.

5. Conclusions

In this study, the hydraulic performance characteristics are investigated for various important geometric and real flow parameters. The cross flow turbine design equations for the velocity ratio, blade angle and the radius ratio are derived. From the present study results, the following major conclusions are obtained:

1) The analytical results obtained from the model considering real flow condition in turbine, are satisfactorily agreed with the results from experimental model tests. The maximum hydraulic efficiency from analysis is 65%. And the ones from model tests for CFT1 and CFT2 are 62% and 72% respectively at the present study.

2) The flow deviation angle, which is expressed as flow losses in blade passages, causes the kinetic energy transfer ratio of runner to be decreased. However, in the range over 0.45 of the velocity ratio, the kinetic energy transfer ratio at the second stage is increased because the absolute inlet velocity is accelerated by the deviated exit flows at the first stage.

3) The tangential flow is one of the primary factors decreasing the hydraulic efficiency. The installed shroud, by which the tangential flow is reduced, is effective to improve the hydraulic efficiency.

4) The nozzle flow coefficient is not constant but decreased as the velocity ratio increases.

5) The hydraulic performance characteristics are linearly varied with the openning rate of guide vane.

6) The position of the second stage flow moves toward the nozzle edge when the rotational speed increases. Therefore the arc angle of exhausted tangential flows are reduced.

Acknowledgement

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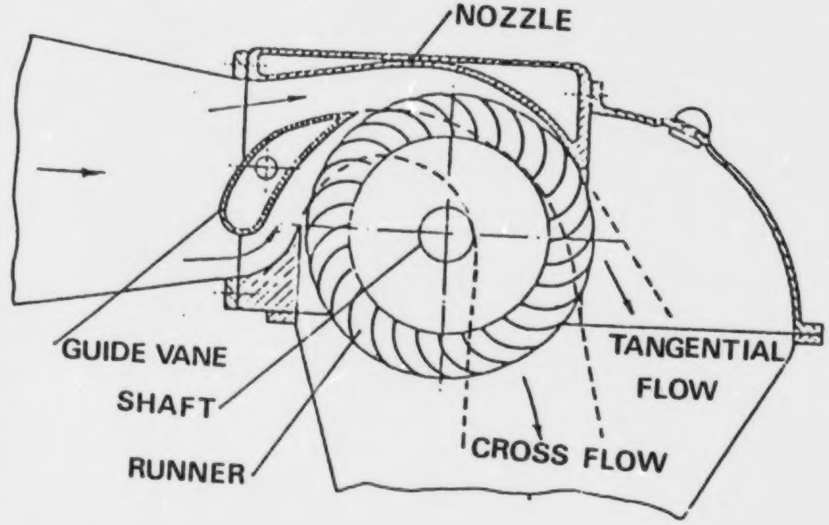
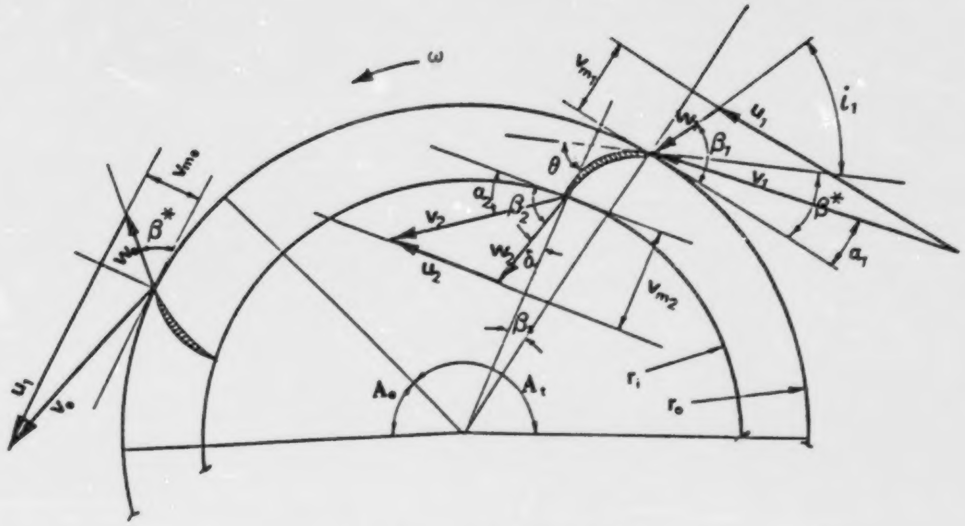
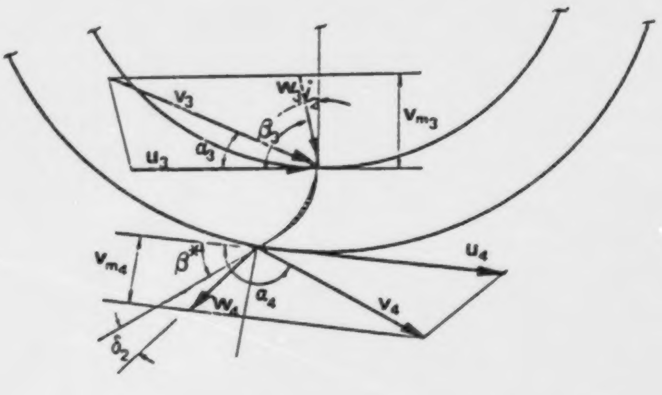

NOZZLE
GUIDE VANE
SHAFT
RUNNER
TANGENTIAL FLOW
CROSS FLOW

FIG.1 FLOWS IN CFT WITH HORIZONTAL INLET


ω
v_{m1}
u_1
i_1
w_1
β_1
θ
v_1
β*
α_1
α_2
β_2
v_2
w_2
δ_1
u_2
v_{m2}
β_1
r_i
r_o
A_t
A_e
v_{me}
W_e
β*
u_1
v_e

(A) AT 1ST STAGE


V_3
W_3
V_{m3}
β_3
α_3
u_3
V_{m4}
β*
W_4
α_4
V_4
u_4
δ_2

(B) AT 2ND STAGE

FIG.2 VELOCITY VECTORS OF CFT FLOW

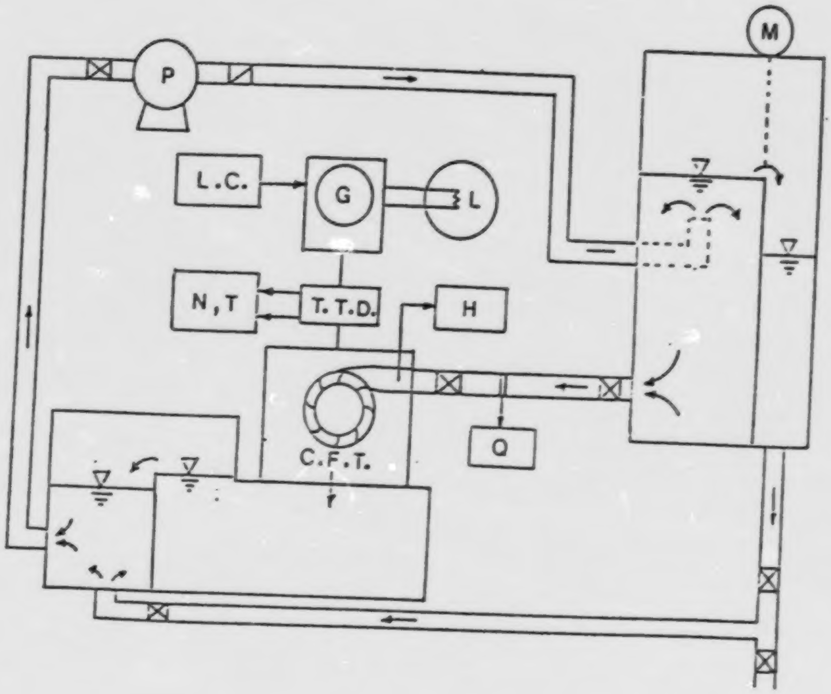

M
P
L.C.
G
L
N,T
T.T.D.
H
C.F.T.
Q

FIG.3 SKETCH OF TEST FACILITY

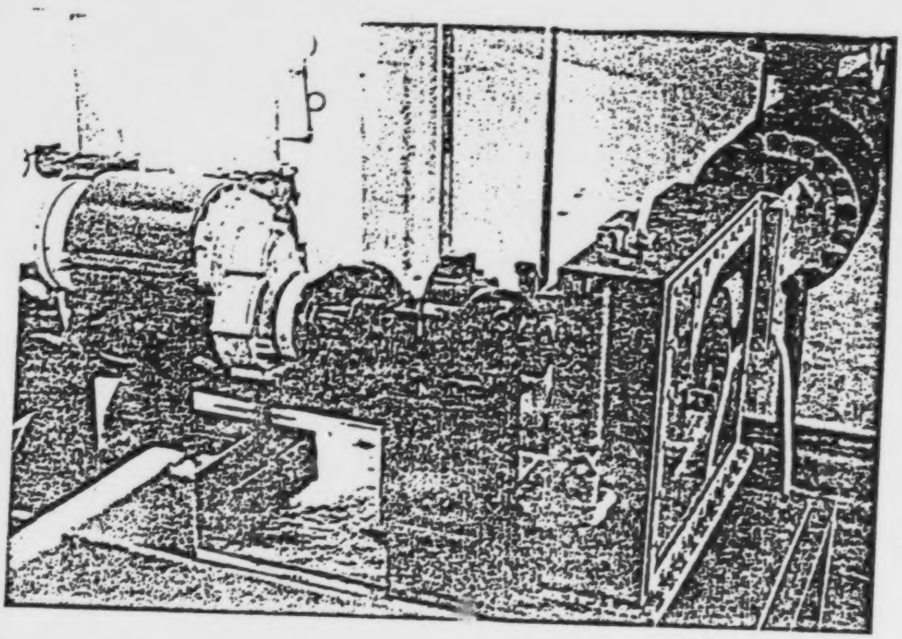


FIG.4 PHOTOGRAPH OF MODEL CFT

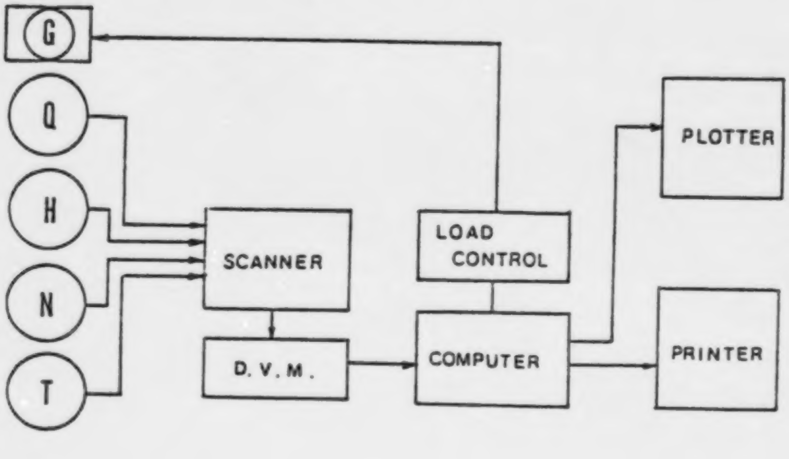

G
Q
H
N
T
SCANNER
D.V.M.
LOAD CONTROL
COMPUTER
PLOTTER
PRINTER

FIG. 5 ON – LINE SYSTEM

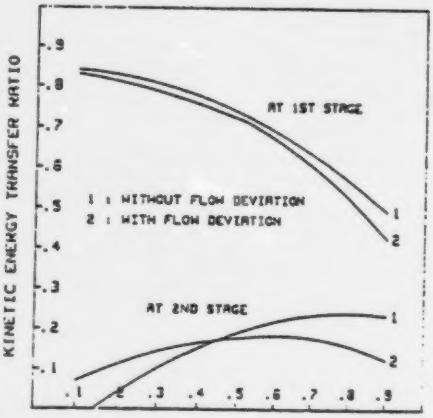


FIG.6 CURVES OF KINETIC ENERGY TRANSFER RATIO

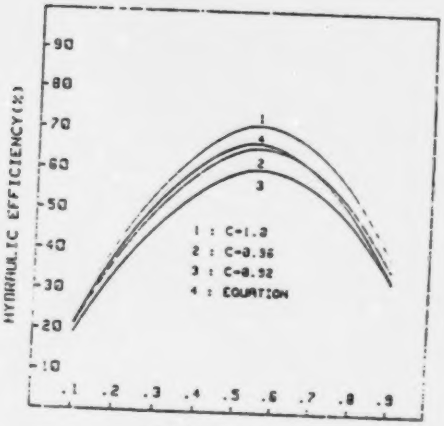


FIG.7 EFFECTS OF NOZZLE FLOW COEFFICIENT ON HYDRAULIC EFFICIENCY

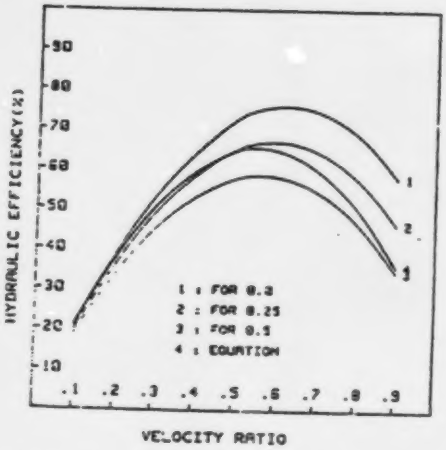


FIG.8 EFFECTS OF TANGENTIAL FLOW RATE RATIO ON HYDRAULIC EFFICIENCY

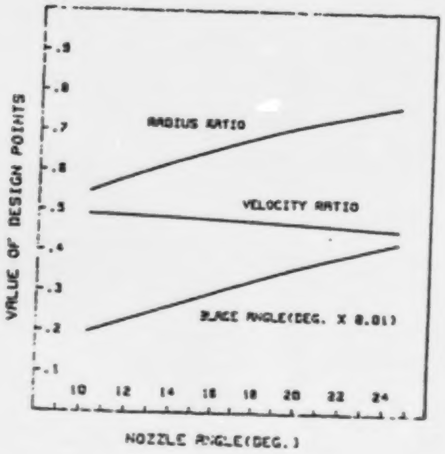


FIG.9 VARIATIONS OF DESIGN POINTS FOR DESIGN NOZZLE ANGLE

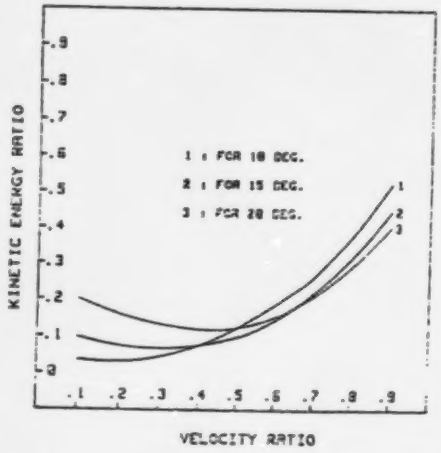


FIG.10 CURVES OF KINETIC ENERGY RATIO AT THE 2ND STAGE EXIT FLOW

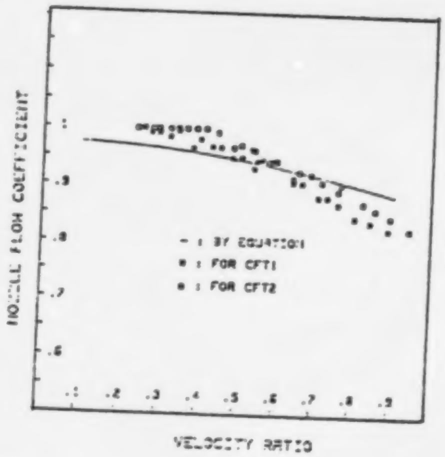


FIG.11 VARIATIONS OF NOZZLE FLOW COEFFICIENT

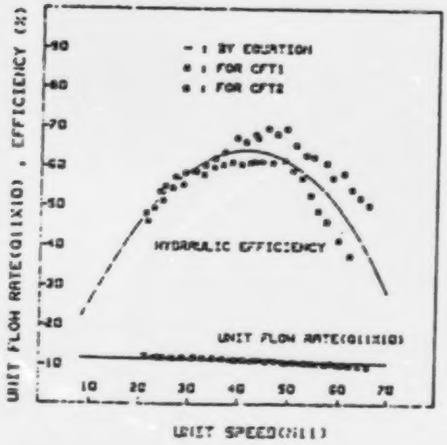


FIG.12 VARIATIONS OF HYDRAULIC EFFICIENCY AND UNIT FLOW RATE

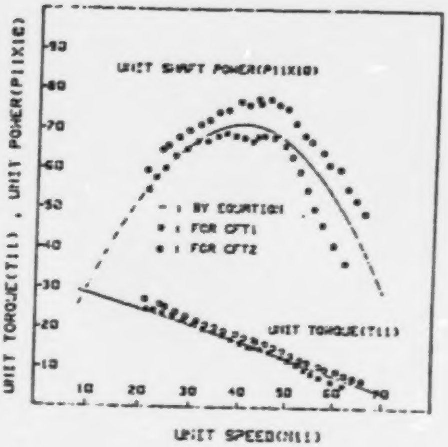


FIG.13 VARIATIONS OF UNIT TORQUE AND UNIT SHAFT POWER

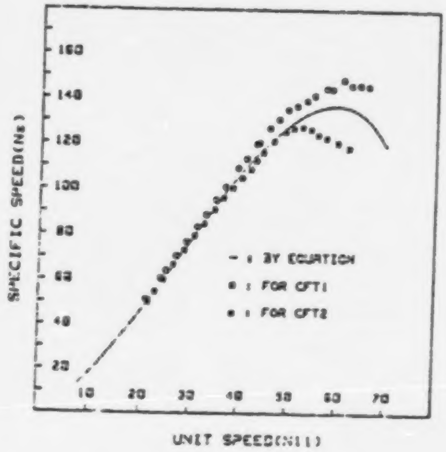


FIG.14 VARIATIONS OF SPECIFIC SPEED

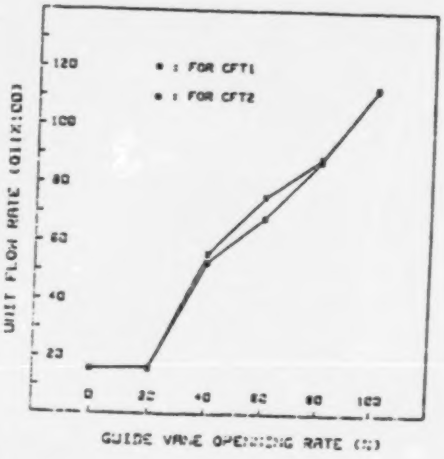


FIG.15 VARIATIONS OF UNIT FLOW RATE WITH GUIDE VANE OPENING RATE

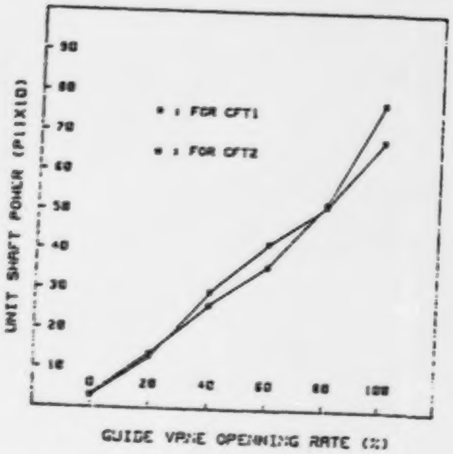


FIG.17 VARIATIONS OF UNIT SHAFT POWER WITH GUIDE VANE OPENNING RATE

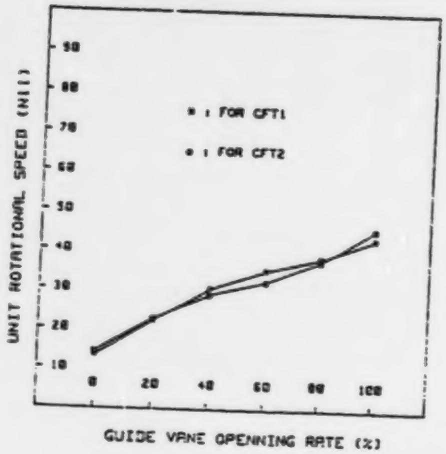
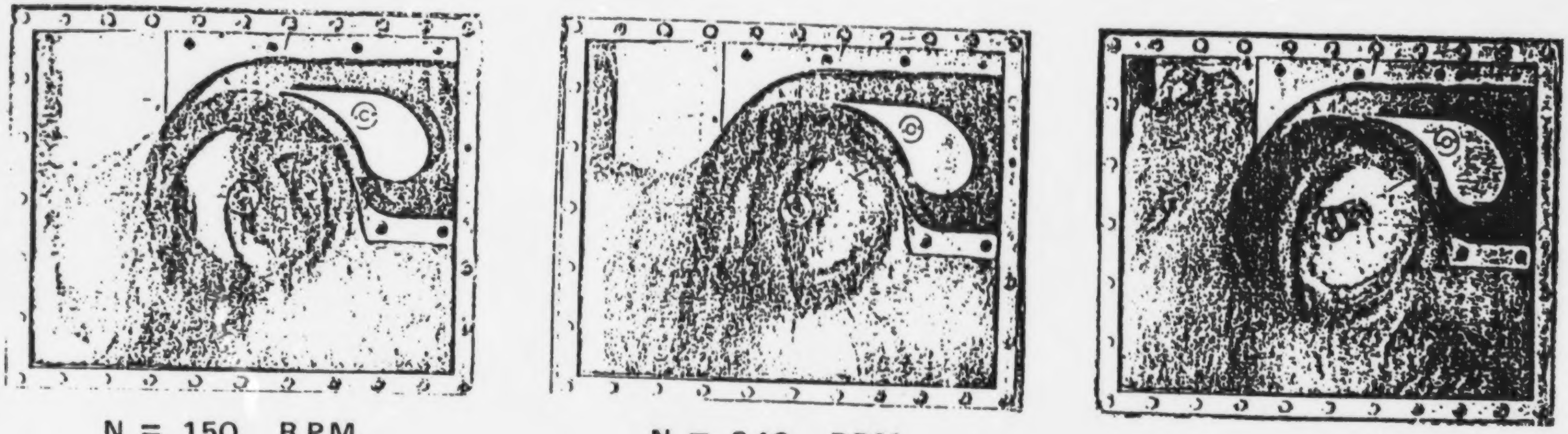


FIG.16 VARIATIONS OF UNIT ROTATING SPEED WITH GUIDE VANE OPENNING RATE

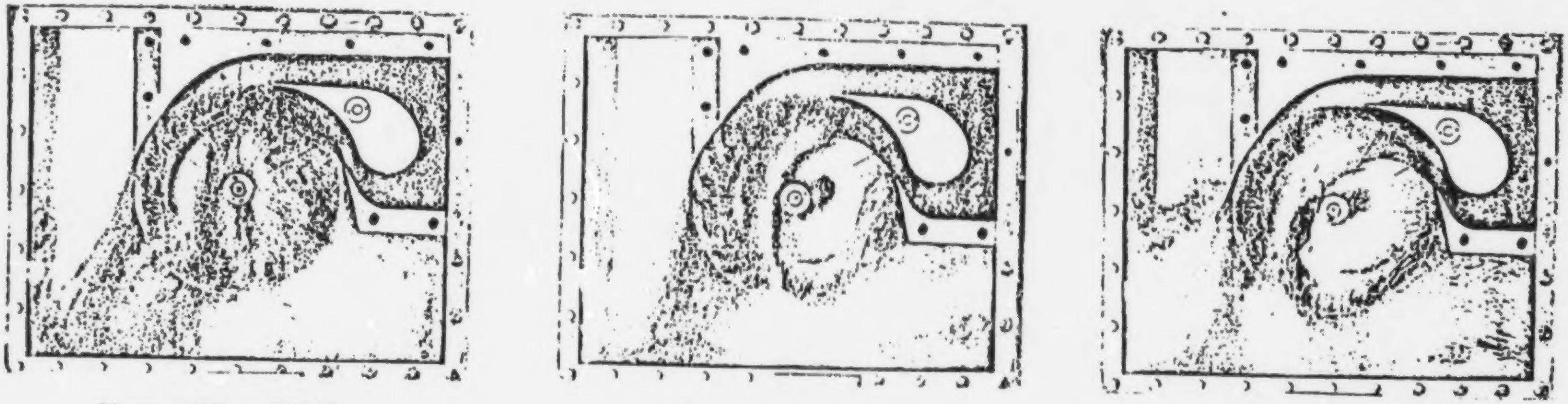


N = 150 R.P.M.

N = 240 R.P.M.

N = 330 R.P.M.

(A) FOR CFT1



N = 150 R.P.M.

N = 240 R.P.M.

N = 330 R.P.M.

(B) FOR CFT2

FIG. 18 PHOTOGRAPH OF FLOW PATTERNS IN MODEL CFT

SESSION 7:

SYSTEM DESIGN ' B'

Chairperson: J. Gordon
Monenco

Design and Operation of Small Hydro Facilities for Winter Conditions

By
P.J. Rae, J.E. Anderson, G.V. Contronel

7

DESIGN AND OPERATION OF SMALL HYDRO FACILITIES FOR WINTER CONDITIONS

by

P.J. Rae, J.E. Anderson and G.V. Cotroneo
Acres International Limited
Niagara Falls, Ontario

Introduction

Small hydro facilities throughout Canada, and in many other areas of the world, must contend with winter conditions for a significant portion of their annual operation. The operational difficulties which might arise from ice conditions can have a significant impact on both the operating and maintenance costs and the revenue produced by the project. This paper reviews several principal features of the winter operation of small hydro stations which can affect annual energy production and the flexibility available for the scheduling of daily generation. The nature and extent of studies which can be undertaken during the development of a small hydro site are discussed.

This paper is not intended as a comprehensive discussion of ice engineering as it relates to hydro-electric design but rather serves to emphasize its importance in the planning and design process.

Experience from the operation of existing hydro facilities allows for the design of new sites which can be expected to operate reliably even though our understanding of many aspects of the formation and behavior of ice is incomplete.

Effects of Winter Conditions

As noted above, this paper focusses on problems which reduce the energy produced by small hydro developments and those which can affect the daily operation of the plant. The specific areas discussed are:

- increases in energy losses due to the presence of ice cover on intake canals and forebays,

- reduction of net head due to the effect of ice cover and ice jams on tailrace levels,
- plugging of intakes by the accumulation of frazil, slush ice or ice floes,
- the possibility of ice cover disruptions downstream as a result of daily peaking operations,
- changes in the ice regime after construction of a reservoir which alters the development and breakup of the ice cover in the reach.

These problems are common to all hydro-electric developments in northern regions, however they can be particularly severe in the case of small hydro developments which are often located on small rivers and characterized by a low gross head or small flow rate. The loss of head is of course much more significant when a plant has a relatively low head available for generation.

Well established development in flood prone areas upstream and downstream of a hydro site can be susceptible to ice regime changes. Unless the effects of hydro development on the ice regime can be assessed, with some confidence, the potential indirect costs which could accrue to other land owners along the river may significantly reduce the project benefits.

River Ice Analyses

The investigation and analysis of the ice regime of a particular reach provides the engineer with the information required to evaluate potential problems associated with a hydro development. The ice processes at work in the river and the effect of the proposed development on the ice regime must be understood if the nature and extent of potential problems is to be determined.

River ice conditions which affect the operation or design of hydroelectric plants in northern climates typically arise from ice cover freeze-up or break-up processes. Characteristics of the ice cover throughout the winter period, such as its roughness and thickness, are also related to the type of ice formation.

Various forms of heat loss contribute to the gradual decrease in water temperatures at the onset of winter. When the water temperature falls slightly below the freezing point (0^{o} C), supercooling occurs and different types of ice are produced, (thermal or frazil) depending on heat loss at the water surface or the river bed and the river turbulence. Thermal ice is static and grows as a surface layer on slow moving bodies of water. A thermal ice cover will commonly form in a lake or as border ice along a river. Ice formation can also be dynamic such as where frazil ice crystals are produced in a relatively rapid flowing turbulent stream. After it has formed, frazil ice accumulates on the surface forming slush ice, ice pans, etc which, when combined with increasing border ice growth, results in the lodgement of a stationary cover at congested control locations.

A river ice cover will often be formed by juxtaposition of the surface ice pans and floes. If a critical condition at the leading edge of the ice cover is not achieved, ice will be carried below the cover where it is deposited in lower velocity areas. This increases the flow losses below the cover and increases the water level until the ice cover becomes stable and progresses upstream. Some reaches may remain open throughout the winter and continue to produce frazil ice. This ice is carried downstream to be deposited on the ice cover, in forebays or as anchor ice on the river bed. The process of ice cover formation results in higher water levels which are generally sustained throughout the winter period.

At the end of the winter, warmer weather reduces the strength of the ice cover while snowmelt increases the river discharge. When the decreasing internal and external (loss of bank contact) resisting forces in the ice cover can no longer withstand the increasing downstream forces, the ice cover collapses and begins to move downstream. Ice jams develop at sites where the ice cover has not dislodged causing a rapid increase in water level, often resulting in flooding.

The ice processes described are complex, requiring a firm understanding of thermal, hydraulic and structural engineering processes. Further details about the formation and breakup of river ice covers can be found in a number of publications including Michel(1971). Both physical and numerical model studies have been used to investigate potential ice related problems at the design stage of a hydroelectric project or actual ice problems which occur during plant operation.

Physical Model Studies

Physical model studies have been used to study ice effects where predictive techniques are either unavailable or unreliable. This is particulary true where hydro project costs are large in comparison to the cost of physical model studies.

Froude number similitude is commonly used to determine model scales and in calibration of the model for an open water flow condition. Due to the complex nature of river ice processes, scale problems are encountered with ice properties such as its strength, friction, cohesion and density, the scaling of the thermal ice processes to simulate ice generation and the transport of the various forms of ice produced. A number of different materials are used to simulate ice properties in hydraulic models. These include synthetic materials or natural ice which has been chemically doped to simulate the primary ice processes. In all cases, the supply of ice is estimated and provided as an input to the model.

Hydraulic models which simulate ice conditions are calibrated by matching the model behavior to ice conditions observed in the field. Conditions used for model calibration include ice cover progression and the location of lodgement points and ice jams. Regardless of their inherent difficulties in scaling and reproduction of prototype conditions, model studies are considered by many to be the most reliable means of assessing the implications of ice processes on the design and operation of hydroelectric plants. Model studies are the only method presently available for reproduction of two and three dimensional problems in the vicinity of forebays and intakes.

One of the major disadvantages of physical model studies for small hydro developments is the cost of the studies.

Numerical Modeling

Numerical modeling offers a viable and generally less costly alternative for the analysis of certain problems. Ice processes which can be analyzed using numerical methods include,

- the rate of thermal and frazil ice generation
- the cover progression rate, extent and thickness of a developing ice cover at freeze-up,
- the extent and thickness of ice jams,
- ice forces in an ice cover (jam),
- river water levels resulting from ice processes.

Numerical models are currently used to assess problems such as,

- the extent of frazil ice accumulation in a headpond or at a power plant intake structure.
- the impact of flow and headpond conditions on the start or delay of ice cover formation or breakup, the severity of ice jams and the resulting water levels,
- winter tailwater levels under various ice conditions,
- winter water levels during construction diversions.

Acres has used the numerical river ice simulation model ICESIM to study the impact of river ice in a large number of Canadian rivers which vary considerably in both extent and size. The ICESIM model has been used to address a wide range of concerns from the overall concept or layout of a project to developing operational guidelines. Applications have included design studies as well as the analysis of post construction conditions. Several other models have been developed and are in use by other organizations in Canada.

ICESIM is a time-step steady state, gradually varied flow backwater model which simulates the major ice processes of a thermal or fragmented river ice cover during the freeze-up or break-up periods. The model uses a number of empirical and physically based formulae to characterize different ice processes which affect the water profile along a river, including:

- the rate of ice generation
- ice cover advancement by juxtaposition of ice
- ice submergence in high velocity areas and transport to areas of lower velocity
- erosion of an unconsolidated ice cover
- thickening of an ice cover to achieve mechanical stability

The hydraulic backwater profile is recomputed to update the velocity and water level conditions in the river as the ice regime changes. The reader is referred to Petryk (1986) for a more detailed description of the ICESIM model.

The model uses basic river geometry, hydraulic, ice and meteorological data as input. The estimated values of various ice parameters depend on the type of event being modeled (break-up or freeze-up) and are adjusted within the range of experience during the model calibration. Calibration is more important in the case of river ice models than for the relatively well understood open water backwater models. The number of degrees of freedom available to the modeler is relatively large and field observations are normally used to confirm the results of the model for selected calibration events.

Field Investigations

Field observations are considered to be the most important part of an analysis of ice conditions in a river reach. Ice problems are very site specific and their analysis depends on knowledge of river dimensions and other information concerning the ice processes. The interaction of numerous processes may occur at a site and correct interpretation of the dominant process usually depends on careful observation of the problem. Physical models and numerical analyses need to be checked against quantitative observations to establish a degree of confidence in the predictions which are to be made.

The scope of a field measurement program is dictated by the specific objectives of the investigation. However, field operations are expensive and the scope of the program is usually constrained by budget limitations. A field program is normally formulated to address a specific concern and to supplement other sources of information such as historical river flow and stage records, climatological records and records of earliest ice observations.

The choice of the boundaries of the area of observation is important. The extent of the field observations upstream and downstream of the site of interest can best be decided from a preliminary understanding of the prevailing processes gained during a reconnaissance of the area.

The timing of observations may also be critical. Some phenomena can only be understood by repeated observations over the entire winter. Examples are the assessment of the total quantity of frazil and slush ice deposited under the ice cover in a river reach or the determination of the minimum temperature of water in a reservoir. Some, such as the freeze-up or break-up of ice cover, can only be observed once each year, at a time which can only roughly be predicted.

In deciding on the scope of observations, the natural variability of the conditions being measured must be considered. Fundamental determinants such as air temperature, snow cover and river flow are features of the weather and subject to a wide range of variation. To draw significant conclusions based on purely statistical observations may require repeated observations, perhaps over several seasons. Therefore most investigations seek to establish causal relationships which will permit a range of possible conditions to be explored by analysis or simulation.

Table 1 provides a broad summary of field programs which are commonly carried out to obtain thermal and hydraulic data for analysis of river ice problems related to hydroelectric developments.

When planning a winter field program logistics are very important. Equipment failure and human errors are more likely and may jeopardize the results of the program or put investigators in positions of risk.

Winter Ice Conditions

In Canada, below freezing temperatures can be expected from October through to March and ice will generally be present in many rivers and lakes from November through to April. The timing of formation and breakup of the ice cover will of course depend to a large degree on the location being considered and its specific meteorological, hydraulic and hydrological conditions. The period over which ice conditions can be encountered represents a significant portion of the year and if ice conditions reduce plant output during this period the potential loss of revenue can be large.

The nature and extent of problems encountered at a particular site are a function of the ice regime in the river reach upstream and downstream of the proposed development. The supply and nature of ice produced in the reach will vary through the winter as the ice cover develops and temperatures of the air and water change.

Impact of Ice on Energy Production

An ice cover affects energy production by reducing the net head available. The presence of an ice cover on an intake channel increases the head losses by reducing the cross sectional area and increasing the wetted perimeter of the section. With a reduced cross sectional area the flow velocity must be increased to maintain the desired flow rate.

The ice cover at a plant intake will normally be formed by the juxtaposition of surface ice arriving from the upstream reach. The thickness of the cover at formation can be predicted from the hydraulics of the channel using the results of Pariset et al (1966). The cover will subsequently thicken by thermal growth. The designer can calculate the increase in head loss at a plant by estimating the thickness and roughness of the ice cover.

Downstream of the plant, the tailwater level is increased by the formation of the ice cover in the downstream reach, subject to the peak power plant discharge during formation. The ice cover thickness and water level increase is of course site specific and can be estimated using numerical methods. The combination of head reductions at the intake and tailrace can have a significant but predictable impact on the energy production. This loss of energy in the winter period can be of the order of 3-5 % at a small hydro site. While not a large percentage it is significant and reduces the project revenue in the key winter season. These effects are strongly site specific and must be evaluated for each site considered. The exact magnitude at some sites may be much larger and have an impact on the viability of the development. The reduction of head due to ice covers occurs every year through the months with an ice cover.

Energy is also by intermittent interruptions of the plant due to ice conditions. It is much more difficult to quantitatively predict the effect of these interruptions on the energy produced by a project. However, the characteristics of sites free of ice problems can be used in design. Fouling of an intake occurs by accumulation of frazil ice at trashracks or by the presence of ice on the surface which is drawn down to the intake because of inadequate submergence. Frazil ice is formed in open water reaches upstream of the plant and carried long distances either in open water or below the ice cover. Immediately after formation frazil is very cohesive and will stick to metal surfaces. After a short time the crystals become inactive and will only foul an intake when accumulated in a mass. Intakes must be properly designed to avoid fouling by ice if energy losses and operating difficulties are to be avoided.

Intake Design

The accepted standard for the design of a small hydro intake is to ensure that a stable ice cover will form upstream of the plant. The ice cover insulates the water surface and prevents generation of ice in the vicinity of the plant. A small forebay is often provided to increase water level enough to for the ice cover to become stable. The forebay also stores ice carried from the reach upstream of the plant and prevents it from reaching the intake. If the ice covered reach is long enough all frazil crystals reaching the intake will be inactive and should pass through the power plant without fouling the intake.

Majewski (1984) suggests that some savings can be achieved if the plant flow rate is reduced while the cover is forming to achieve a smooth surface which will have a lower roughness coefficient. The stability of the cover under design conditions is ensured by having a Froude number based on the open water depth not greater than approximately 0.08 as discussed by Michel (1971).

In some cases conditions may preclude the formation of an ice cover at the intake site. This can occur where the cost of excavation required to construct the intake is large or where the thermal stresses in the ice cover cannot be resisted by the intake/forebay walls. An intake can be designed to operate with an open water forebay by increasing the flow velocity so that an ice cover will not form. Relatively warm water flows into the open approach area from below an upstream ice cover and is cooled as it approaches the power plant. If the rate of cooling is low enough then significant quantities of ice will not be generated in the approach area. A sluice is generally provided at the intake to remove any ice which does accumulate at the structure. An ice boom is used at the upstream end of the intake channel to retain the ice cover in the river. This concept is used at a power station on the St. Mary's River in Ontario and is described by Lariviere (1987) for Hydro Quebec's Archipel project in Lachine.

This approach could also be used at sites where an ice cover is not required to protect the intake from accumulations of active frazil ice. In this case fouling of the intake would be caused by the accumulation of ice at the structure which is carried into the canal by the current and forced under water to the intake. If frazil does not cause problems the channel could remain open with the ice controlled by a boom.

The arrangement of intakes must be made with a full understanding of the ice regime in the reach and the potential problems which could affect the project. The selected design must be appropriate for the site in question so that the loss of energy in the winter period is minimized.

Effects of Ice on Plant Operations

Many small hydro developments are used for peaking to respond to daily load variations in the electric system. This mode of operation places a higher value on the energy generated in the daily peak periods. To generate peak power, the forebay is used to store water during the off-peak period. The plant is then operated at the highest possible capacity during the peak period. The resulting daily cycle of increasing and decreasing flows can de-stabilize a previously stable consolidated ice cover in some sensitive areas. If disrupted, the ice cover may re-consolidate under the increased forces resulting in thickening followed by an increase in the water levels. This can cause winter flooding in areas downstream of the plant which may result in a significant loss to some land owners.

It is possible to analyze and predict the response of an ice cover to water level and flow velocity variations. Acres (1980,1984) examined the behavior of ice covers subject to flow fluctuations. Generally, it was found that if the ice cover is formed at a relatively high steady flow rate, then the plant can be used for peaking and the ice cover will rise and fall with flow variations but without further consolidation. The added stresses in the cover during high flow periods are transferred to the banks through naturally occurring hinges which are formed where the cover bends.

Some loss of flexibility in the operation of the hydro development may still be experienced. There are sites where the effect of a flow pulse can affect the ice cover stability at sensitive reaches after long distances where there is little or no effect. In these instances, the duration and peak of a flow pulse must be restricted so that channel storage effects attenuate the peak downstream flow. The conditions for stability of the ice cover can be estimated analytically and the attenuation of flow pulses determined using routing methods.

Changes in Ice Regime

The construction of a small hydro development which includes a forebay or reservoir will alter the ice regime in a river reach, possibly changing how and when the ice cover forms and breaks up. Changes in the ice regime are caused by the alteration of the thermal and flow regimes downstream of a reservoir after construction. Upstream of the structure the higher water level will also cause changes in the ice regime. The effect of these changes must be evaluated to ensure that potential negative impacts on other property owners or at sensitive structures such as bridges or water intakes are identified before construction.

The presence of a reservoir will regulate the river flows generally increasing winter flows. These higher flows will create a thicker, stronger ice cover which provide more ice during break-up. The formation of the downstream ice cover will also be delayed by the release of relatively warm water from the reservoir so that it advances more rapidly, later when the ice generation is greater in colder temperatures. The presence of the reservoir/forebay will also increase the levels upstream of the reservoir and change the processes by which the cover advances. Changes in the thermal regime may also cause the ice cover downstream of the plant to break-up earlier in the spring when the ice downstream is stronger and more dense. The net effect is that the occurrence and location of ice jams during spring break-up will be changed possibly affecting other river users.

The potential impacts of ice regime changes are assessed by examining changes in the discharge and water levels before and after construction of a development. The analyses will consist of four main activities, as discussed in Yu and Lavender (1982),

- ice surveys to provide data and information on ice processes,
- definition of the flow regime,
- definition of the thermal regime, and
- ice mechanics analyses.

These studies are conducted with the aid of numerical methods which predict the water level and ice regimes for a range of hydrologic and meteorologic conditions.

Summary

Several aspects of the design and operation of small hydro developments in winter conditions were discussed in this paper. The object has been to emphasize the importance of considering ice conditions in the development of small hydro sites. The nature and role of field investigations, physical models and numerical models has been discussed.

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Table 1

Scope of Ice Observation Program in Relation to Specific Objectives

	Thermal Characteristics Ice Formation	Midwinter Ice Cover
Engineering problems and/or applications	- powerhouse or intake fouled by frazil ice	- hydraulic structures designed for ice thrust and hydrodynamic forces - stable ice cover used as winter road or landing strip
Field Measurement program objectives	To Determine: - thermal budget for streams - extent of ice generating reach - rate of thermal exchange between air and water - rate of frazil ice generation, border ice and thermal ice cover growth	To Determine: - physical characteristics of thermal ice cover - thermal characteristics of ice cover - ice management methods
Scope of field measurement	- Air and water temperatures - Thermal gradient along the channel - Structure and size of frazil and ice forms	- Water levels - Ice cover thickness - Flow velocities below ice cover - Ice and water profiles - Thermal gradient of the ice cover

Table 1 (cont'd)

Scope of Ice Observation Program
in Relation to Specific Objectives

	Hydraulic Characteristics Ice Cover Formation	Breakup (Ice Jam)
Engineering problems and/or applications	- flooding caused by river ice - loss of head due to high winter tailwater level - limiting hydropower discharge to maintain stable ice cover downstream from powerhouse - design of ice boom	- flooding caused by river ice jam (need to limit discharge) - loss of head due to high winter tailwater level - blocking of water supply at intake - design of ice boom
Field Measurement program objectives	To Determine: - flow resistance caused by ice cover - high water level due to reduction of conveyance - hydrodynamic forces exerted on structures - ice scour and erosion damage to river banks - limit of operating flow range of a power plant to retain a stable ice cover downstream	To Determine: - flow resistance - rapid increase of upstream water level due to flow constriction below the ice jam - change of flow release due to formation or breakup of ice jam - dislodge ice jam
Scope of field measurement	- size of ice floes - water level upstream and downstream of the ice cover - thickness of the ice cover - flow velocity below ice cover - measurement of ice, water level and channel profiles - geometry of 'ice hinge'	- size and strength of broken ice - water levels upstream and downstream of the ice jam - flow velocity below ice jam - measurement of ice, water level and channel profiles

Design and Commissioning of the Dillon Dam Hydroelectric Project

By

D.M. Clemen, S.J. Hayes

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DESIGN AND COMMISSIONING OF THE DILLON DAM HYDROELECTRIC PLANT

by David M. Clemen[1] and Stanley J. Hayes[2]

The Dillon Dam Hydroelectric Project for the Denver Water Board consists of a single horizontal-shaft Francis turbine directly coupled to a 1976 kVA, 14 pole, synchronous generator. Water is supplied from Dillon Dam Reservoir (3,300 acres) via a closed cylindrical penstock to the inlet of the turbine. A butterfly valve provides shut-off service of the water to the turbine for emergencies or maintenance. A bypass valve system prevents disruption of flow into the Blue River when the unit is not operating.

The generating equipment was bid as a complete "water to wire" equipment supply, installation, check-out, and commissioning package. The lead contractor for the equipment was Hawker Siddeley Power Engineering Inc.; the turbine was by Gilkes Inc. and the generator was by Brush Electric.

Electrical Control System

The Generator Control Switchgear did not include a programmable controller (PC) although they are the current trend. The rationale for not using a PC was based upon the existing skills available from the client's plant operators and maintenance personnel. These operators and maintenance personnel were familiar with hard-wired pumping stations, and had not been trained to maintain and/or operate PC's at the time this plant was to be commissioned. Therefore it was decided to maintain our plant controls as a hard-wired system to better facilitate the use of the client's existing personnel.

The switchgear was a standard 5 Bay control system package utilizing approximately 40 control relays with the associated control switches and meters on the front of the panel. All protective relays were individually mounted and located in one control bay of the switchgear. All protective relay types were approved by the connecting utility to ensure that this station would not be detrimental to the utility's system integrity in any possible manner.

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Spare AC & DC control relays were installed in the switchgear before it was shipped from the factory. These were included in the switchgear to expedite commissioning as extra permissive/interlock circuitry will inevitably be added in the field during unit commissioning.

A VAR/PF controller was required by the utility in order to maintain our power factor at unity. Even if the utility had not required a VAR/PF controller, we have decided from past experience that these are essential to ensure that the utility system does not drive this small, unmanned generator into an over or under excited condition.

Automatic start-up of the unit consisted of pushing one "Unit Auto Start" pushbutton. Opening of the inlet valve, operation of all unit auxiliaries, synchronizing, and unit loading would then be sequenced automatically via the hard-wired control relays.

Manual start-up of the unit consisted of the operator initiating each unit auxiliary individually e.g. opening the inlet valve; starting the governor oil pumps; opening the wicket gates to their "speed no load" position to obtain rated RPM; and then manually synchronizing the unit using a synchroscope, two frequency meters, and two voltmeters. After synchronization to the system, the operator manually loads the unit to the desired kW value by controlling the wicket gate opening with a control switch on the front of the generator switchgear.

A sync-check relay was included in both our manual and automatic start-up circuitry to avoid any out of phase attempt at closing the generator breaker by the operator or the auto-synchronizer.

Plant Lightning Protection

Due to the powerhouse location at a 9000 ft elevation in the Rocky Mountains, the powerhouse and switchyard were protected from direct lightning strokes by a UL Master label certified system. The powerhouse system consisted of numerous lightning air terminals mounted on the perimeter of the roof. These air terminals as well as all equipment and personnel hatches were connected together, and then to the ground mat, with 4/0 bare copper cable.

The switchyard was protected by two shield wires which run the length of the switchyard.

Incoming surges into the switchyard are stopped by three metal oxide surge arresters mounted on the dead-end structure. Three additional metal oxide surge arresters are mounted immediately in front of the main power transformer for additional protection of this transformer.

All control cables from the switchyard to the powerhouse, and all phone cables had zener diode surge protectors and gas tube type surge arresters connected to them. The zener diode surge protectors suppress high speed, low energy overvoltage transients. The gas tube type surge arresters suppress high energy induced surges.

All down conductors for surge protection were connected to the ground grid. The ground grid total resistance for the switchyard and powerhouse ground mat was 1.7 ohms. This value is significantly less than the 50 ohms required by the ANSI/NFPA-78 Lightning Protection Code and less than 5 ohms required by IEEE 142 for small installations.

Unit Speed Governing System

The client specified a Woodward UG-8 mechanical speed governor for standardization with his other hydroelectric plants. This unit is on a relatively long penstock (approximately 1200 ft.), which can make unit speed stability problematical; however, the unit only operates in parallel with the electrical utility, so frequency regulation under isolated load is not required. The contract documents required bidders to submit calculations with their bids which documented the off-line stability of their proposed unit.

Unit Check-Out

A list of "check-out" procedures was established prior to start-up and commissioning. Check-out of the various systems requires that the vendor representatives be on-site to verify the integrity of their equipment. Electrical check-outs usually include point to point continuity checks on all external wiring, meggering of motors, adjustment of all generator switchgear devices e.g., RTD temperature monitor, bench tests of the protective relays, etc. Mechanical checks usually include hydrostatic testing of pressurized fluid systems (hydraulic oil, cooling water, etc.), alignment and runout checks of the unit shaft system; clearance checks for the runner, wicket gates, shafts, and bearings; and operational checks of major mechanical systems (hydraulic oil pressure set, cooling water pumps, etc.).

It is very important to establish a complete list of "check-out" procedures and have the various vendors sign-off once each item of equipment has been checked-out. Field calibration of all pressure switches, flow switches, level switches, RTD's, etc. was an integral part of this "check-out" procedure for each system. These "check-out" procedures will ensure that the subsequent unit start-up and commissioning phase will proceed rapidly.

Start-Up and Commissioning

Start-up and commissioning of the unit was accomplished from the middle of June to the middle of July 1987 with a 2 week interruption to diagnose/eliminate problems with governor speed stability and the Automatic Voltage Regulator (AVR) as detailed below.

1. Governor Speed Stability

During initial unit testing, the governing system could only hold the unit speed within a 30 RPM band, which was too wide to permit synchronization (synchronous speed for this unit is 514.3 RPM). Review of project documentation revealed there had been miscommunication between the turbine supplier, governor supplier, and generator supplier; and that the mechanical inertia of the rotating system as-installed was less than that recommended by the governor supplier. The obvious solution of adding a flywheel to increase the mechanical inertia was undesirable due to the inherent difficulties in retrofitting a flywheel onto the existing unit, and the resulting delay for the project (estimated as 6 months minimum).

Improvements in the off-line speed stability were achieved by modifying the governor to improve the responsiveness to speed fluctuations, and increase the stability of the governor response. Specific changes to the governor included adding new flyballs, changing the flyball springs, changing the ballhead oil to a lighter grade oil, and modifying the internal hydraulic compensation. In addition, the wicket gate opening and closing times were speeded up. The initial gate timing was conservatively slow to minimize transient pressure rise in the penstock; the final, faster timing greatly improved governor response, and still resulted in penstock transient pressures within the penstock design pressure.

As a result of the modifications, the off-line speed variation was reduced from a band of 30 RPM to a band of one to two RPM. This negligible speed variation enabled the auto-synchronizer to readily and reliably synchronize the unit. It should be noted that the modifications also greatly reduced the on-line frequency regulation capability for the unit; however, since the unit was not required to provide any frequency regulation capability, the modifications did not negatively impact unit operation.

2. AVR Field Forcing

The Basler AVR supplied with the unit (Model No. SR125 H) did not include a Volts/HZ sensing circuit integral with the assembly to prevent underfrequency overexcitation. A speed switch set at approx 60% rated rpm was utilized to initiate the excitation system. We found that the 60% setting was much too low, resulting in our AVR field forcing our excitation system while our unit was at 60 to 70% rated RPM. This caused high field volts/amperes for a sustained period of time; and caused the single phase, capacitor start governor drive motor (which was fed from the excitation system) to fail.

The solution was to use a speed switch setting of approx 90% rated speed to initiate the excitation system thus avoiding sustained field forcing while the unit was ramping-up to this 90% value.

Other commissioning procedures and problems encountered were:

1. VAR/PF Controller

The VAR/PF controller was improperly connected to the AVR and Maximum Excitation Limiter. Moreover, the incorrect potentiometer (500 ohms vs 5000 ohms) had been mounted on the front of the generator switchgear for manual control. These two errors would normally be identified during the factory inspection of this switchgear. In this case, they were not identified because the switchgear manufacturer did not have the necessary test equipment available to check this VAR/PF controller when we arrived for the factory inspection. This problem emphasizes the importance of checking and testing all generator switchgear circuitry/equipment during the factory inspection prior to its shipment to the field for installation. Verification that the manufacturer has the equipment to perform the necessary tests should be confirmed prior to the actual inspection date.

2. Phase Rotation Check

A phase check was performed at the Generator Circuit Breaker to ensure the generator phase rotation matched the utility system phase rotation. The utility linemen had previously connected the high voltage leads of the switchyard to their system without doing a phase rotation check as this check is the independent power producer's responsibility. The phase check we performed confirmed that we were connected improperly across the generator breaker. The phase connections were corrected before synchronization was attempted.

3. Hydraulic Power Unit

The hydraulic power unit has 2 pumps operating in a lead-lag configuration. The specifications required the pump/motor assemblies to cycle on and off to maintain system pressure. The controls were also designed to let the pumps start unloaded, and unload before stopping. Due to the hydraulic system design, leakage within the system was causing the lead pump to cycle on and off every 90 seconds. The basic system design prevented any significant reductions in system leakage. The pump controls were modified such that the lead pump/motor unit runs continuously and loads and unloads to maintain system pressure. This modification eliminates the excessive stress and fatigue caused by frequent on/off cycling.

4. Utility Tests

Some utilities have extensive test programs that the independent power producer is required to complete before allowing connection to their grid. This is the utilities prerogative to ensure a reliable grid. At Dillon, this test program added approximately 2 1/2 days to the unit commissioning time; and required coordination concerning the specific utility personnel to be in attendance during the various tests. An awareness of the specific utility tests required and the amount of commissioning time/personnel necessary should be an item of concern for every independent power producer.

It should be mentioned that the utility was extremely cooperative in making their personnel available as required during the Dillon Dam Commissioning.

5. Telephone-Influence Factor (TIF)/Wave Form Deviation Factor Tests

TIF tests were performed with a Spectrum Analyzer to ensure we were within the IEEE 115 code limits. This would ensure that no interference to the existing area communication lines would occur. The generator harmonic levels were very acceptable, however, we did discover significant 3rd and 5th harmonics already existing on the utility system.

The wave form deviation factor oscillograph photographs of the generator and system wave forms confirmed what the spectrum analyzer had shown in the TIF test i.e., the utility waveform did not have a very good sine-wave shape due to the significant 3rd and 5th harmonics.

The oscillograph photographs and TIF data regarding the utility system voltages were submitted to the utility to assist them in locating the source of these harmonics on their system.

Unit Load Rejection Tests

Load rejection tests were performed at 25, 50, 75, and 100% of maximum unit output. At each load point, a "hard" load rejection (generator breaker immediately opened) was performed. Transient parameters such as turbine inlet pressure and rotational speed were recorded on an oscillograph for analysis. The load rejection testing served two main purposes: first, to ensure that the wicket gate closure rate was slow enough to keep the maximum transient inlet pressure below the penstock design pressure, and second, to determine the maximum transient unit speed. An overspeed switch was provided with the unit to initiate unit shutdown. This overspeed switch was set at 20 RPM above the maximum transient overspeed to automatically shut down the unit in the event the unit should go into a runaway condition.

Turbine Index Test

Turbine index tests were performed on the unit (measurements of unit output and relative flow for the full range of unit operation). This testing served several function.

- Checked the maximum unit output for comparison with the guaranteed capacity.
- Determined relative unit performance through the operating range.
- Provided a benchmark of unit performance for later comparison.

Index tests should be performed periodically throughout the life of the unit to check for any deviations or deterioration in unit performance.

Conclusion

The availability of the Dillon Dam unit since the July start-up and commissioning has been greater than 95%. Governor stability was resolved to everyone's satisfaction by speeding up the wicket gate opening and closing time, and fine tuning the governor flyball assembly. The remaining problems with the AVR, VAR/PF controller, phase rotation, and hydraulic power unit were solved in a logical manner once they were identified.

The unit check-out procedures which were established minimized the time required for start-up and commissioning. Field testing verified the unit performance guarantees, optimized unit performance, and provided data to adjust the unit controls to ensure safe operation. As a result, client satisfaction with the unit has been very high.

Technology - Selecting Strategy for Small Hydro Development

By
S.T. Su, T.P. Tung

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Technology - Selecting Strategy for Small Hydro Development

S.T. Su* and T.P. Tung**

INTRODUCTION

Numerous opportunities and choices are now available to apply the technological innovations that have matured in the past few years to small hydro development, from computer-based site-screening to innovative equipment and structural design. On the other hand, constraints from local and site conditions have increased, primarily due to ecological and economical concerns. The latter are especially relevant for the developing countries where needs are more diverse and resources are more limited.

Maximizing opportunities under constraints constitutes the need for a well-considered strategy which can serve as a master guide for the implementation of small-scale hydropower projects.

The purpose of this paper is to present a methodology for deriving such a strategy based on the current state-of-the-art technologies in small-scale hydro development, including inventory of local resources, constraints and site conditions. The technological mix is then checked against the local constraints to assess its suitability and to identify alternatives of development. Computer programs capable of handling [illegible] amounts of information are used to provide project ranking and key financial parameters.

The outcome of this technology-selecting strategy is expected to improve the quality of the decision-making for prioritizing the development of small-scale hydro projects to best meet the local and other specified needs.

OPPORTUNITIES FOR APPLYING TECHNOLOGY INNOVATIONS

The need to reduce the small hydro installation and capital costs has prompted the improvements of the existing technology and demonstration of new techniques and designs. These include site assessment technique, new turbines and generating equipment improvements, and innovative civil structure and arrangement.

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1. Site Assessment and Costing Methodologies

Examples in this category are hydrologic design methodologies for small hydro at ungauged sites and development of micro-computer site-screening and costing programs. The hydrologic design manuals and computer programs developed under Canadian governments sponsorship provide guidance for determining design flows and flood at small hydro sites without requiring costly studies. Methodologies involve developing regional flow-duration curves and "turbinable flow" curves by relating characteristics of curves to physiographic and climatic parameters [Judge, 1985]. In a feasibility-level study for the Atlantic Provinces, synthetic daily flow sequence data were generated for potential sites, and energy and revenues were estimated by computer simulation [Acres, 1985]. Similar work has just been completed for the Ontario Region [Anderson, 1988].

In the Province of British Columbia, studies using watershed modeling techniques were developed in 1986 [Howard, 1987]. The mountainous terrain of British Columbia with its myraid of micro-climates precluded methods of regional analysis based on regression or comparisons with gauged streams. The program IMP (Integrated Method of Power Analysis) was developed around the philosophy that a conceptual model of physical processes in the atmosphere and on the land is the best way to quantitatively bring together all of the information that can be used to estimate runoff from ungauged watersheds. The watershed model will generate a continuous daily time series of streamflow for an ungauged site based on daily precipitation and temperature time series [Howard, 1986]. A flood frequency analysis program uses topographical information specific to the site and rainfall information to generate the flood frequency curve. A hydropower simulation program determines the daily energy output based on selected generation facilities and the hydrologic daily time series generated by the watershed model. Currently, an evaluation and improvement of this program for B.C. application is being carried out.

A user-friendly micro-computer program SHYDRO for costing small hydro has been prepared and is available to the public [Monenco, 1986]. SHYDRO was initially applied on a small-hydro inventory study in New Brunswick and Prince Edward Island, and subsequently for the Province of Nova Scotia. More recently it has been utilized by ShawMont Newfoundland Ltd. (SNL) on two extensive small-hydro inventory studies. This program estimates the cost of a hydro development on the basis of sixteen site-specific parameters. These parameters have been restricted to those that are readily available from large-scale maps, thereby avoiding the cost of site visits and surveys. The program first calculates the "least cost" based on a simple formula developed by a statistical analysis of cost data from 141 sites [Gordon, 1986].

It then calculates the cost of the following components:

Dam, Spillway, Intake, Penstock, Unwatering, Powerhouse Civil, Equipment Supply and Erection, Access Road, Transmission Line and Substation, Fishway, Contractor's Overhead Engineering and Owner's

Cost, Interest During Construction

The Present Project being carried out by SNL is to produce an enhanced and more versatile "second generation" version of SHYDRO. It can easily be applied by non-specialist engineers to do preliminary evaluations of the economic feasibility of small-hydro sites.

2. New Turbines and Generating Equipment Improvement

Various turbine types have been improved and new turbines developed and applied to specific site conditions in North America, such as: low-head, pit-type turbine; belt-drive, straight-flow (rim) turbine and generator, and the higher head application (up to 30m) of the tubular-type turbine. There are several different types of prepackaged mini and micro hydro turbine equipment that have been installed at a number of North American sites. Some of these include "Hydrolec", a cross-flow turbine package made of plastic material, and the recent application of submersible "Flygt" package. The factory-built and tested, packaged units are compact enough for easy shipping to the site, and can be quickly installed. This concept is opening up new potential for low-head hydro in remote locations. Another "water to wire" self-contained system, "Mini-Hydel", features a complete hydro-generating facility enclosed in a tubular powerhouse which can be transported and installed in one piece.

One unique mini-hydro turbine developed by a Canadian Firm, the so-called "L" turbine, has a patented tangential inlet producing the necessary swirl flow characteristics at the turbine inlet. The high angular velocity induced by the tangential inlet negates the use of guide vanes and is especially advantages in high trash environments.

There are ultra-low-head turbines for water-current applications being developed and tested. The application of pump-as-turbines, and variable speed or induction generators in off-grid application are being demonstrated.

3. Innovative Civil Structure and Arrangement

Use of syphon penstock across existing dams, packaged turbo-generating units placed at the top of a syphon loop across the dam and intake is headed downward, and another so call "power-barge" with syphon penstock across the spillway have been developed. Discharge outlets at existing small dams can be used as penstock inlets leading to a turbine installation. Penstock may be constructed of polyethylene, fibreglass and PVC material. Use of local material and skills for construction of the dam (i.e. rock-filled timber crib dam), use of prefab powerhouse building and other simplified construction and installation techniques have been carried out.

Some potential remote sites are often located at low-head rapids or falls of large and relatively wide rivers. It is possible to design a proper intake structure and penstock or canal carrying flow to the small-hydro plant downstream of the rapids. It is also possible to have the packaged station located above the rapids and with long draft tube extending downstream. A dam may not need to be built, with a resulting cost savings. A non-dam river scheme will have minimum environmental impact and could be more easily accepted by the local community. There is a need to further standardize and modularize all aspects of small-hydro engineering, equipment and installation.

LIMITATIONS AND CONSTRAINTS

Basically, there are two types of factors which determine whether a small hydroelectric site can be viably developed. The first type relate to the power production and potential such as topography and hydrology or, simply expressed, as the head and flow. The other types relate to the limitations and/or constraints of power generation. These factors include site accessibility, power transmission, local resources and environmental concerns. It is as a result of interaction between these two types of factors that a suitable technology is suggested. A typical example is shown in Figure 1.

They types of data relating to the power production potential at a site as well as the site limitation and constraints are briefly discussed:

1. Physical Data

   - Historical stream flow and flood data at the site or at nearby sites; reservior operation levels, records or agreements on water use or water rights at the site; the effects of upstream storages; any effects of icing; headwater levels and tailwater rating curves.

   - Topographic maps, record drawings and design criteria, prior contract plans and specifications, operating manuals, equipment specifications, plans for other proposed upstream or downstream developments.

   - Subsurface exploratory data, geological reports, construction and operating records and photographs, records of past repairs and remedial work, verbal information from those familiar with the facilities.

2. Accessibility Data

   - Isolated Sites - Where standby diesel is required, the average annual generation mix of diesel and hydro can be determined for use in estimating alternative costs on a year-by-year basis. Usually, its limited use will permit the assumption of longer life of the mechanical facilities before replacement. For isolated sites where electrical power is presently available from small diesel generators, the rural systems may be designed to provide only 12-hour service. Also no provision may be made for back-up reserves. A small hydropower plant could be extended to provide 24-hour service, and be considerably more reliable. Even though 24-hour service will be available from the hydroelectric sites, this does not mean that all available power will be utilized at all hours of the day. Much more likely is a large decrease in night time and early morning consumption for isolated areas. This may decrease the total cost of alternative generation at an isolated site as compared to a grid-tied site where all potential power generation would ordinarily be utilized by the grid. Daily studies should therefore be used to assess usage for isolated sites since monthly studies would tend to obscure this diurnal variation in power and energy demand.

- Grid-tie Sites - The hydro unit could function differently in the type of service provided to local load centre than that for an interconnected systems; for example, the provision of late night and early morning generation, spinning reserves, and energy peaking power. The demand for energy in the local area may account for only a small proportion of the potential hydro output.

- Delayed Grid-Tie Sites - The eventual connection of an isolated site to a transmission grid combines elements of analysis considered in the above two sections on isolated and grid-tie projects. As previously mentioned, a grid-tie hydro site will ordinarily be more efficient for the system than an isolated site due to increased utilization of the energy production. For a given hydro project at a specific site, therefore, the corresponding alternative generation costs will be higher when it becomes a grid-tie site. A consideration for delayed grid-tie sites is that the timing of the interconnection may influence the size of the initial installation which is based on the net cost differential as well a local demand. A short interim period may justify the provision of future capacity in all physical features of the hydro projects, while a longer period may warrant provisions for deferred capacity in the civil works only.

3. Operational Data

- At most potential small hydroelectric sites, the water to be utilized by the plant is already required for downstream uses such as irrigation or domestic water supply. While this demand does not prohibit the supplementary use of water through the hydro plant, it can constrain the operational flexibility of the plant and may seriously affect the power output.

- As with most energy sources, energy from small hydroelectric plants is more valuable if it can be generated at a high rate during the daytime, or peak demand hours rather than at a lower rate on a 24-hour basis. However, if the water is otherwise required to be released on a relatively uniform basis downstream, or if a large fish release is required, a peaking operation may not be acceptable.

4. Environmental Data

- Data required for environmental analysis such as water quality, fish, wildlife and botanical resources, archeological or historic resources, recreation and land use. The range and amount of environmental data vary greatly in regard to the developmental stage of the countries, i.e., the developing vs. the developed countries.

COMPUTER-AIDED STRATEGY FORMULATION

The crucial factor to a successful development is a good understanding of the site potential, as well as the constraints associated with the particular site and local conditions. For small hydro development, a traditional comprehensive feasibility study would be difficult to justify, for the reasons of its cost and time required to complete such study.

A computer program which is capable of rapidly processing the site potential and constraints under different equipment and civil structure configurations is the focal point of the strategy formulation. The basic idea of this computer-aided technology selection strategy is to utilize fully the potential of power generation from the site and, at the same time, select the most economical equipment and civil works which are appropriate and efficient.

One example is a computer program developed by Tudor Engineering Company. It can process vast amounts of information and provide ranking of the alternatives. The program has a sub-routine to store the cost information of the different technologies identified. Either cost curves or inputted cost data can be used. The capital cost and operation and maintenance cost of the resulting project is then calculated. From the particular project configuration, the flow data and the targeted operation, the average annual energy production and the corresponding revenues are calculated.

The technological choices and site conditions are organized into the following data files:

- Technological Data - Friction factors for each segment of the headrace conduit; the type of civil works and turbine; the number of units; the project dependable capacity factor (the percentage of time the plant should produce a steady power yield).

- Economic Parameters - The period of economic analysis; the anticipated project life; the construction period; on-line date; the value of energy and capacity during economic analysis; inflation rates; other construction costs (roads, transmission lines, etc.); and input cost curves for the dam and different equipment packages configuration.

- Hydrology Data - The periodic data for the headwater stream; low flow maintenance release criteria for fish water and other site-specific data.

The final step of the program is an analysis of revenues and costs to give a ranking of the alternatives in accordance with the following financial criteria:

- Net Revenues
- Revenue/Cost Ratio
- Internal Rate of Return
- First Year Cash Flow
- Minimum Cost per kWh

Output shows the thirty best alternatives under each of the financial criteria.

After reviewing the output the user may examine any layout in detail. The program produces on demand for a selected projects:

- The main equipment and civil works parameters
- A detailed cost analysis
- Cash flow for the life of the project
- A summary of operation data

Run time for the program for each headrace conduit profile is about three minutes on VAX 750. Both "run-of-the-river" and "storage" projects can be optimized for technological selection at a given site.

Table 1 is one sample result reflects the ranking of project alternatives by: (1) maximum present worth of net revenues, (2) maximum revenue/cost ratio, (3) maximum internal rate of return, (4) first year cash flow, and (5) minimum cost per kilowatt hour. Table 2 to Table 5 are samples of output in detail.

CONCLUSION

In determining the best project configuration, computer programs similar to the above examples provide a very useful tool to quickly and thoroughly review all the project alternatives. For small and mini hydro projects, care should be taken to provide an updated equipment and civil structure related cost data.

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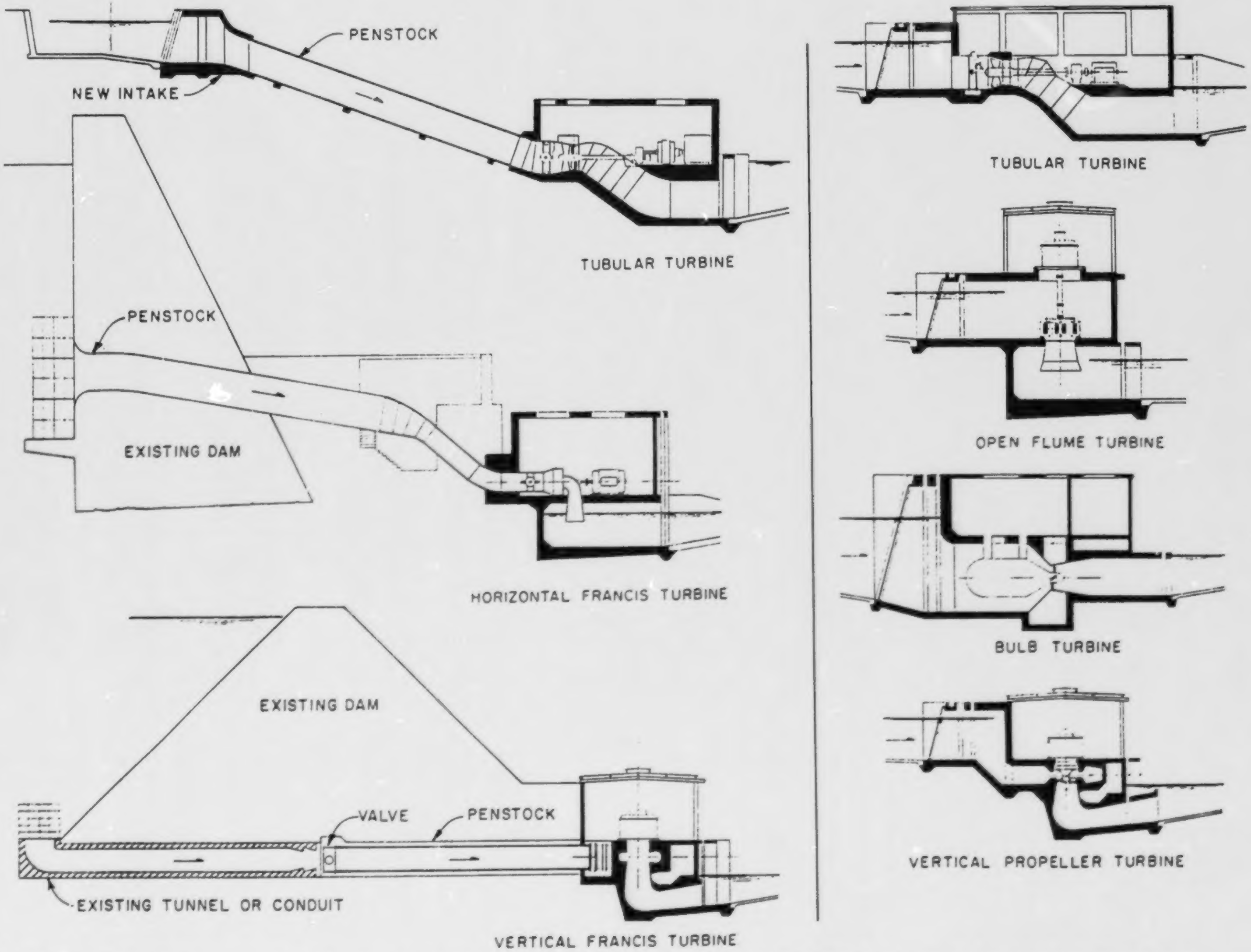
PENSTOCK
NEW INTAKE
TUBULAR TURBINE
PENSTOCK
EXISTING DAM
HORIZONTAL FRANCIS TURBINE
EXISTING DAM
VALVE
PENSTOCK
EXISTING TUNNEL OR CONDUIT
VERTICAL FRANCIS TURBINE
TUBULAR TURBINE
OPEN FLUME TURBINE
BULB TURBINE
VERTICAL PROPELLER TURBINE

NOTE: The various project types can utilize turbine types other than those shown in the above examples.

Figure 1 ALTERNATIVE INSTALLATIONS

TABLE 1

FEASIBILITY PARAMETERS BASED ON MAX. P.W NET REVENUE

****

% EXC.	FLOW (CFS)	POWER (MW)	ENERGY (GWh/YR)	% HLOSS	P.W COST	P.W REVENUE	P.W NET REV.	REV/COST RATIO	INT. RATE OF RETURN	1ST. YEAR CASH FLOW	MILLS PER KWh
8	220.00	26.368	48.607	10.0	34357.	71115.	36758.	2.070	19.8	1764.	72.7
8	220.00	25.782	47.851	12.0	33280.	70008.	36728.	2.104	20.0	1792.	71.5
10.	191.00	22.892	46.186	10.0	31043.	67572.	36529.	2.177	20.6	1841.	69.1
8.	220.00	25.196	47.094	14.0	32378.	68901.	36523.	2.128	20.2	1803.	70.7
8	220.00	26.954	49.364	8.0	35708.	72222.	36514.	2.023	19.4	1708.	74.4
10.	191.00	23.401	46.953	8.0	32257.	68695.	36438.	2.130	20.3	1800.	70.7
10.	191.00	22.383	45.419	12.0	30076.	66450.	36374.	2.209	20.9	1857.	68.1
6	261.00	30.586	50.533	12.0	37689.	73932.	36243.	1.962	18.9	1631.	76.7
6.	261.00	29.891	49.808	14.0	36660.	72872.	36212.	1.988	19.1	1658.	75.7
8.	220.00	24.610	46.337	16.0	31596.	67794.	36198.	2.146	20.4	1801.	70.1
6.	261.00	31.282	51.257	10.0	38917.	74992.	36075.	1.927	18.7	1584.	78.1
10	191.00	21.874	44.652	14.0	29267.	65328.	36060.	2.232	21.0	1856.	67.4
6.	261.00	29.196	49.083	16.0	35766.	71811.	36045.	2.008	19.3	1671.	75.0
10.	191.00	23.909	47.720	6.0	33900.	69817.	35917.	2.060	19.7	1714.	73.1
8.	220.00	27.539	50.121	6.0	37536.	73329.	35793.	1.954	18.9	1602.	77.0
8.	220.00	24.024	45.581	18.0	30900.	66687.	35787.	2.158	20.5	1790.	69.7
6.	261.00	28.501	48.358	18.0	34971.	70751.	35781.	2.023	19.4	1674.	74.4
10	191.00	21.366	43.885	16.0	28567.	64206.	35639.	2.248	21.2	1845.	67.0
6	261.00	31.977	51.982	8.0	40457.	76053.	35596.	1.880	18.3	1505.	80.1
6	261.00	27.806	47.634	20.0	34248.	69691.	35443.	2.035	19.5	1669.	74.0
8	220.00	23.438	44.824	20.0	30269.	65580.	35312.	2.167	20.5	1772.	69.5
12	160.00	19.603	43.493	8.0	28462.	63633.	35171.	2.236	21.1	1813.	67.3
10	191.00	20.857	43.118	18.0	27943.	63083.	35140.	2.258	21.2	1825.	66.7
12.	160.00	19.176	42.741	10.0	27400.	62533.	35133.	2.282	21.4	1840.	65.9
6	261.00	27.111	46.909	22.0	33581.	68630.	35050.	2.044	19.6	1659.	73.6
12	160.00	18.750	41.989	12.0	26555.	61433.	34878.	2.313	21.7	1845.	65.1
12.	160.00	20.029	44.246	6.0	29901.	64734.	34832.	2.165	20.5	1747.	69.5
8.	220.00	22.852	44.068	22.0	29686.	64473.	34787.	2.172	20.6	1750.	69.3
6.	261.00	26.416	46.184	24.0	32958.	67570.	34613.	2.050	19.6	1644.	73.4
10.	191.00	20.348	42.350	20.0	27378.	61961.	34583.	2.263	21.3	1800.	66.5

TABLE 2

```
                         PROJECT:              ***ALTERNATIVE 14***(3/26/85)
                         *******
                         RATED FLOW (CFS)= 220.
                         % OF HEAD LOSS  -  10.



HYDROPLANT DATA
****************
TURBINE TYPE : PELTON
NO  OF UNITS :              1
RATED FLOW (CFS):        220.
GROSS HEAD (FT) :       1800.
RATED HEAD (FT) :       1620
RATED POWER (MW).         26.368
ANNUAL ENERGY(GWH/YR):  48.607


HEADRACE CONDUIT DATA
*********************
     SEGMENT    CONDUIT TYPE      LENGTH     DIAMETER    WEIGHT        COST
                                   (FT)        (FT)       (LB)       ($1000)

        1       STEEL PIPE        7200.       4.44      752601.        1882.

        2       STEEL PIPE        1344.       3.95      221291.         553.

        3       STEEL PIPE        1100.       3.91      190475.         476.

        4       STEEL PIPE        2576.       3.36     1002488.        2506.
                                                                   -----------
                                    TOTAL HEADRACE CONDUIT COST:       5417.
```

TABLE 3

```
FINANCIAL DATA
**************
INTEREST RATE (%):                     10.00
COST INFLATION RATE (%):                5.00
O&M INFLATION RATE (%):                 5.00
ANALYSIS PERIOD (YR):                  28
AMORTIZATION PERIOD (YR):              28
CONSTRUCTION PERIOD (YR):               2
1ST. YEAR ENERGY VALUE ($/KWH):         0.0982
1ST. YEAR CAPACITY VALUE ($/KWH):       0.0108
WHEELING COST ($/KWH):                  0.0000
POWER AND ENERGY ESCALATION RATE:   5% for 10 years then levelized


                    COST ESTIMATE($1000)
                    ********************
                    TURBINE,GEN.,MECH  & ELECT.  :     5048.
                    POWERHOUSE CIVIL             :     2524.
                    DIVERSION DAM                :      150.
                    HEADRACE CONDUIT             :     5417.
                    MISCELLANEOUS                :      700.
                                                    -----------
                                      SUBTOTAL :      13840.

                              CONTINGENCY (15%):       2076.
                                                    -----------
                   DIRECT CONSTRUCTION COST (1985) :  15916.
                                      ENGINEERING :    2492.
                        ADMIN. LEGAL & FINAN.(3%) :     477.
                                                    -----------
                       TOTAL PROJECT COST (1985):     18885.
                      *TOTAL PROJECT COST (1993):     26573.

                    INTEREST DURING CONSTRUCTION:      3720.
                                                    -----------
                              TOTAL CAPITAL COST:     30294.

* NOTE ESCALATED FROM 1985 TO THE MIDDLE OF THE CONSTRUCTION PERIOD
```

TABLE 4

```
CASH FLOW ANALYSIS
******************
ONLINE DATE                          1993
TOTAL PROJECT COST:                 26573.
INTEREST DURING CONSTRUCTION:        3720.
CAPITAL COST:                       30294.
PRESENT WORTH O&M:                   4063.
PRESENT WORTH WHEELING COST:            0.
PRESENT WORTH REVENUES:             71115.
PRESNET WORTH COST:                 34357.

YEAR   ENERGY    CAPACITY   ENERGY   CAPACITY   TOTAL   DEBT SERVICE    O&M    WHEELING   TOTAL     NET    ACC.NET.
       VALUE      VALUE      REV       REV.      REV.                   COST      COST     COST     REV.     REV.

1993  0.09820   0.01080     4773.      525.     5298.       3255.       279.       0.     3534.    1764.     1764.
1994  0.10610   0.01160     5157.      564.     5721.       3255.       293.       0.     3548.    2173.     3937.
1995  0.11470   0.01230     5575.      598.     6173.       3255.       308.       0.     3563.    2610.     6548.
1996  0.12330   0.01320     5993.      642.     6635.       3255.       323.       0.     3578.    3057.     9604.
1997  0.13230   0.01410     6431.      685.     7116.       3255.       339.       0.     3594.    3522.    13126.
1998  0.13890   0.01480     6752.      719.     7471.       3255.       356.       0.     3611.    3860.    16986.
1999  0.14590   0.01550     7092.      753.     7845.       3255.       374.       0.     3629.    4216.    21202.
2000  0.15320   0.01630     7447.      792.     8239.       3255.       393.       0.     3648.    4591.    25794.
2001  0.16080   0.01710     7816.      831.     8647.       3255.       412.       0.     3667.    4980.    30774.
2002  0.16890   0.01800     8210.      875.     9085.       3255.       433.       0.     3688.    5397.    36170.
2003  0.16890   0.01800     8210.      875.     9085.       3255.       454.       0.     3710.    5375.    41545.
2004  0.16890   0.01800     8210.      875.     9085.       3255.       477.       0.     3732.    5352.    46898.
2005  0.16890   0.01800     8210.      875.     9085.       3255.       501.       0.     3756.    5329.    52226.
2006  0.16890   0.01800     8210.      875.     9085.       3255.       526.       0.     3781.    5304.    57530.
2007  0.16890   0.01800     8210.      875.     9085.       3255.       552.       0.     3808.    5277.    62807.
2008  0.16890   0.01800     8210.      875.     9085.       3255.       580.       0.     3835.    5250.    68057.
2009  0.16890   0.01800     8210.      875.     9085.       3255.       609.       0.     3864.    5221.    73277.
2010  0.16890   0.01800     8210.      875.     9085.       3255.       640.       0.     3895.    5190.    78467.
2011  0.16890   0.01800     8210.      875.     9085.       3255.       671.       0.     3927.    5158.    83626.
2012  0.16890   0.01800     8210.      875.     9085.       3255.       705.       0.     3960.    5125.    88750.
2013  0.16890   0.01800     8210.      875.     9085.       3255.       740.       0.     3995.    5089.    93840.
2014  0.16890   0.01800     8210.      875.     9085.       3255.       777.       0.     4032.    5052.    98892.
2015  0.16890   0.01800     8210.      875.     9085.       3255.       816.       0.     4071.    5013.   103905.
2016  0.16890   0.01800     8210.      875.     9085.       3255.       857.       0.     4112.    4973.   108878.
2017  0.16890   0.01800     8210.      875.     9085.       3255.       900.       0.     4155.    4930.   113808.
2018  0.16890   0.01800     8210.      875.     9085.       3255.       945.       0.     4200.    4885.   118692.
2019  0.16890   0.01800     8210.      875.     9085.       3255.       992.       0.     4247.    4838.   123530.
2020  0.16890   0.01800     8210.      875.     9085.       3255.      1042.       0.     4297.    4788.   128318.
```

OPERATION DATA
****

TABLE 5

%	Q	Q-Qfish	Qturb	Qturb/Qr	Eff	Gen Eff	Turb Eff	Net H	Power	Energy
100	1.00	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
98	2.00	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
96	3.00	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
94	5.00	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
92	5.50	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
90	6.10	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
88	7.00	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
86	8.00	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
84	8.80	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
82	9.30	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
80	9.70	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
78	10.50	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
76	11.30	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
74	11.60	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
72	12.00	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
70	12.70	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
68	13.50	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
66	14.50	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
64	15.20	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
62	16.00	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
60	16.70	0.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
58	18.20	1.20	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
56	19.70	2.70	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
54	20.80	3.80	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
52	22.00	5.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
50	23.20	6.20	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
48	24.90	7.90	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
46	26.50	9.50	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
44	28.20	11.20	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
42	31.40	14.40	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
40	34.60	17.60	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
38	37.00	20.00	0.00	0.00	0.00	97.00	0.00	1800.00	0.000	0.000
36	42.00	25.00	25.00	11.36	87.30	97.00	90.00	1797.68	3.325	0.291
34	46.50	29.50	29.50	13.41	87.30	97.00	90.00	1796.76	3.921	0.635
32	53.00	36.00	36.00	16.36	87.30	97.00	90.00	1795.18	4.781	0.762
30	60.30	43.30	43.30	19.68	87.30	97.00	90.00	1793.03	5.744	0.922
28	65.00	48.00	48.00	21.82	87.30	97.00	90.00	1791.43	6.362	1.060
26	74.00	57.00	57.00	25.91	87.30	97.00	90.00	1787.92	7.540	1.218
24	83.00	66.00	66.00	30.00	87.30	97.00	90.00	1783.80	8.710	1.423
22	95.00	78.00	78.00	35.45	87.30	97.00	90.00	1777.37	10.257	1.661
20	106.70	89.70	89.70	40.77	87.30	97.00	90.00	1770.08	11.747	1.927
18	117.00	100.00	100.00	45.45	87.30	97.00	90.00	1762.81	13.042	2.171
16	135.00	118.00	118.00	53.64	87.30	97.00	90.00	1748.22	15.262	2.479
14	154.00	137.00	137.00	62.27	87.30	97.00	90.00	1730.20	17.537	2.873
12	177.00	160.00	160.00	72.73	87.30	97.00	90.00	1704.79	20.180	3.304
10	208.00	191.00	191.00	86.82	87.30	97.00	90.00	1664.33	23.518	3.828
8	237.00	220.00	220.00	100.00	87.30	97.00	90.00	1620.00	26.368	4.370
6	278.00	261.00	242.00	110.00	87.30	97.00	90.00	1582.20	28.328	4.791
4	350.00	333.00	242.00	110.00	87.30	97.00	90.00	1582.20	28.328	4.963
2	425.00	408.00	242.00	110.00	87.30	97.00	90.00	1582.20	28.328	4.963
0	500.00	483.00	242.00	110.00	87.30	97.00	90.00	1582.20	28.328	4.963

Estimating the Usable Energy of Isolated Run-Of-River Small Hydro

By
K.J. Bennett

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ESTIMATING THE USABLE ENERGY
OF ISOLATED RUN-OF-RIVER
SMALL HYDRO PLANTS

Kearon J. Bennett, P. Eng.
President, Ottawa Engineering Limited

ABSTRACT

The paper presents a graphical methodology for estimating the amount of available energy at a potential run-of-river small hydro site that can be used by a remote community. The methodology is suitable for situations where demand will exceed supply for part of the year.

Estimating the usable energy of an isolated run-of-river small hydro plant is complicated by the fact that available power and energy varies depending on the availability of steamflow (an annual cycle), while demand varies on a daily basis (with some seasonal adjustment).

It will be explained why, in this case, the superimposition of duration curves (power and load) is not a valid method for estimating usable energy.

The methodology assumes that an annual flow-duration curve has been derived for the site and the peak demand and shape of the load-duration curve has been estimated for the remote community. It is assumed that streamflow is constant over a day. Available energy at different flow exceedence values (from 0 to 100% on the flow-duration curve) are compared to the estimated average daily load-duration curve (assumed constant over the year for a given year).

The portion of the demand that can be supplied by the hydro plant for each flow is calculated and plotted as a "supply-duration curve". The area under this curve is the energy supplied by the hydro plant to the community assuming average annual flow availability and the daily load-duration curve for a given year of operation. Supply is then calculated for different peak demands, as predicted by a load growth scenario, and a graph of supply versus peak demand is plotted.

The methodology is a good tool for selecting the installed capacity and economics of a run-of-river hydro plant which will supply a remote community, especially where the best available data for the site are estimated flow-duration and load-duration curves.

BASIC DATA AND ASSUMPTIONS

In order to assess the usable energy from a run-of-river hydro plant at a remote location using the methodology described in this paper, the following information is required:

- Estimated flow-duration curve for the site based on daily values over a period of record of at least ten years (Fig. 1).
- Anticipated load-duration curve for the demand centre (Fig. 2).
- Peak demand forecast for the study period (Fig.3).

It is assumed that:

- there is no storage available at the site
- the load-duration curve represents an average day
- streamflow is constant over a day

It should be clear that the methodology is required only in cases where the available power from the hydro plant is less than the peak power requirements at the remote location for part of the year.

DURATION CURVES

For a given set of data a curve can be constructed that expresses the percentage of data that is equal to or greater than a given value in the data set. When each value represents an average over a given period of time (minute, hour, day, etc.) then the curve can be used to describe the percent of time a value is equalled or exceeded. When used in this context, the curve is called a duration curve.

Duration curves are very useful tools for the assessment of run-of-river small hydro sites. Flow-duration curves are used to select the installed capacity and to estimate the available energy at a site. Similarly, for isolated load centres, load-duration curves provide information about the expected demand.

As the power available at a site is the product of the available head, flow, the gravitational constant and efficiency, a flow-duration curve can be converted into a power-duration curve for a selected design flow (Fig. 4). The area under this curve represents an estimate of the available energy at the site for the design flow.

The estimated energy required at the isolated load centre is the area under the load-duration curve.

It may appear straightforward that a direct comparison of the available and the required energy is possible by superimposing the power-duration and load-duration curves as shown in Figure 5. However, since power and load do not necessarily occur simultaneously, this method is only valid if the development of the site can incorporate sufficient water storage (in which case a different method would probably be used).

In other words, the power available at a run-of-river site will vary from day to day on an annual cycle depending on precipitation. Demand, on the other hand, varies from instant to instant over a day depending on the power usage at any given moment. The flow-duration curve is the result of ordering the flow values over an entire period of record and can therefore be said to represent an average year. Similarily, a load-duration curve can be said to represent an average day.

While power and load duration curves cannot be superimposed they can be used to estimate usable energy from run-of-river hydro plants as described in the following section.

METHODOLOGY

For a selected design flow and estimated load-duration curve for the first year of operation (Fig.2):

1) Construct a power-duration curve as shown in Fig. 4.

2) At each 5% interval on the power-duration curve, determine the corresponding daily power output. Fig. 6 shows an example for 40% (shown as P(40)).

3) Plot the daily power output on the load-duration curve (which represents an average day) and determine the area that lies under the two curves as shown in Fig. 7. This area is the energy that can be supplied by the run-of-river hydro plant over the day.

4) Having done this for each 5% interval, plot a curve of the daily energy supplied by the hydro plant versus the percent of the year (365 days) that the supplied energy is equalled or exceeded - an energy supply duration curve (Fig. 8). NOTE: BE CAREFUL WITH TIME UNIT.

5) Determine the area under the energy supply duration curve. This value is the total energy that can be supplied by the hydro plant over an average year for a given demand. The remaining demand must be supplied by other means.

6) Repeat steps 2 to 5 for several points on the peak demand forecast curve and plot a curve of the energy supplied by the hydro plant versus time (Fig. 9). Use this curve to determine annual energy supplied by both the hydro plant and other means. These values will then form the basis of the economic analysis.

The procedure is repeated for several installed capacities and is used in conjunction with the corresponding cost estimates and the costs of producing the additional energy required to determine optimum plant size.

SIMPLIFIED EXAMPLE

To illustrate the use of the methodology, a simplified example is presented.

Figures 10 and 11 are simplified power-duration and load-duration curves for a hypothetical site. Figure 12 shows the anticipated annual energy requirements at the site for the next twenty years.

Figure 13, 14 and 15 show the daily energy that can be supplied by the hydro plant for power values at the 0 - 30, 55 and 80 percent exceedence points on the power-duration curve. (Steps 2 and 3). Note that above the 80% exceedence point, the power output would be zero.

Figure 16 shows the corresponding energy supply duration curve and the area representing the energy supplied by the hydro plant during the first year in the forecast period. (Steps 4 and 5)

Figure 17 shows the results of steps 2 to 5 for peak demand values on the peak demand forecast curve for years 1, 7.5 and 20. Joining these points yields a curve of the estimated energy to be supplied by the run-of-river hydro plant over the twenty year period.

CAUTION

The user must exercise caution when using duration curves. While they are a very useful tool, they do not indicate the time sequence of events and in the case of flow-duration curves, they do not reveal high and low flow years. A flow-duration curve should be used in conjuntion with an analysis of the annual flow patterns. If flows vary significantly from year to year, then a sensitivity analysis should be done in conjunction with the above methodology.

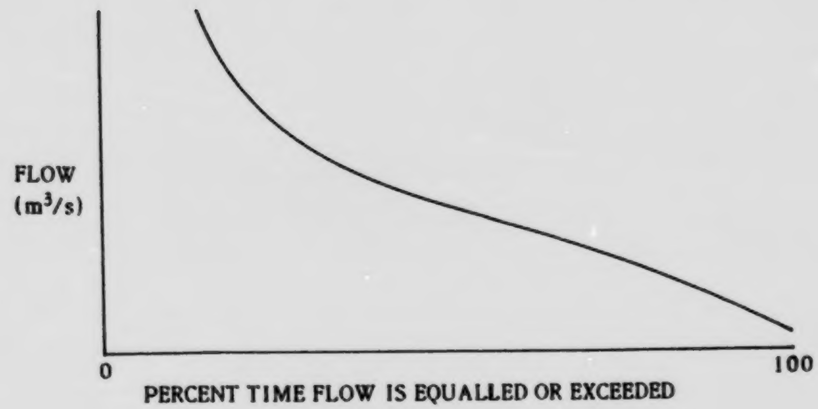

FIG. 1 **FLOW-DURATION CURVE: Flow Variation During an Average Year**

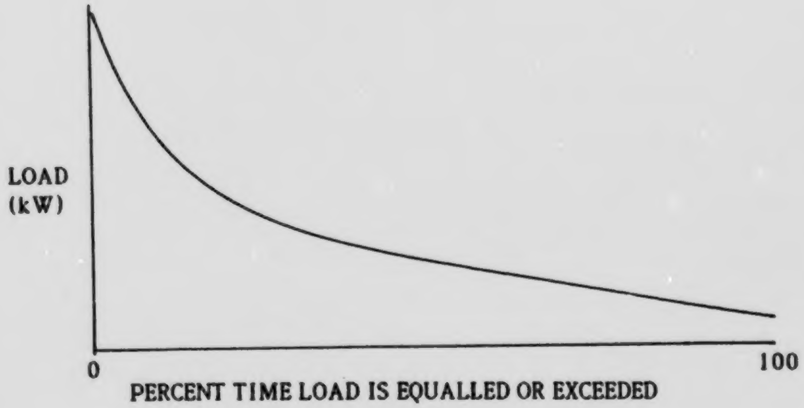

FIG. 2 **LOAD-DURATION CURVE: Load Variation During an Average Day**

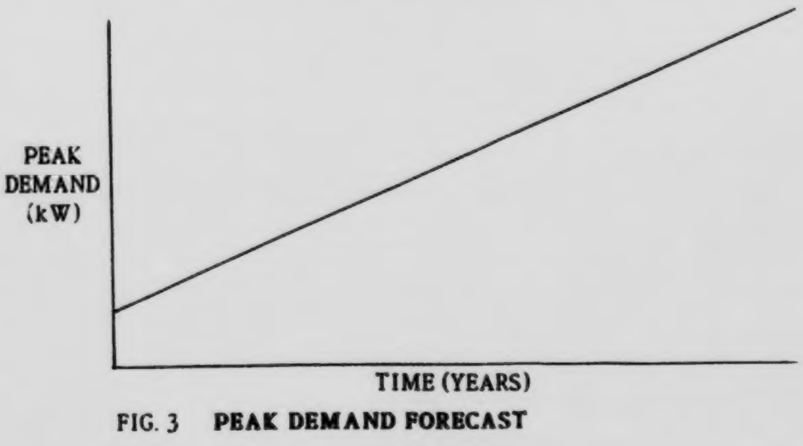

FIG. 3 **PEAK DEMAND FORECAST**

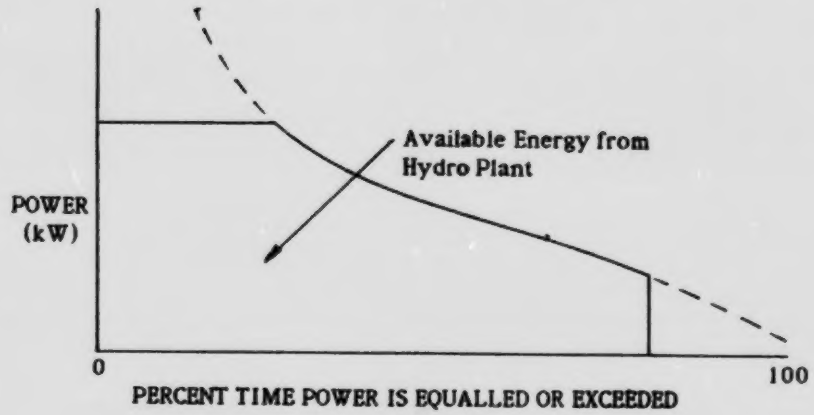

FIG. 4 **POWER DURATION CURVE: (Assuming Constant Head and Efficiency)**

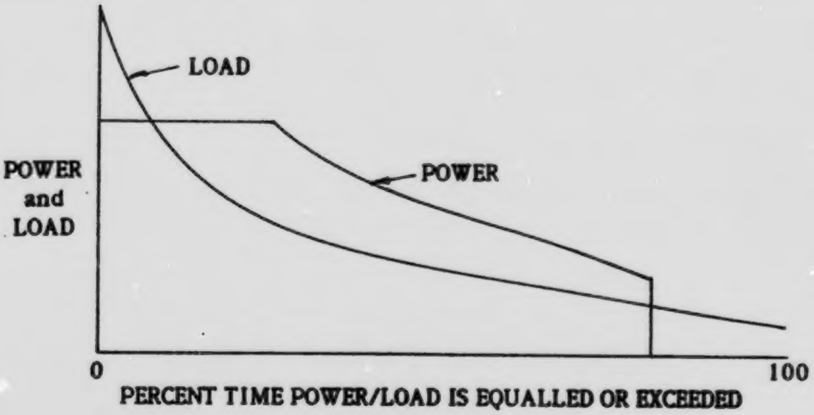

FIG. 5 **SUPERIMPOSITION OF POWER AND LOAD DURATION CURVES: (Not Valid Unless Sufficient Storage is Available)**

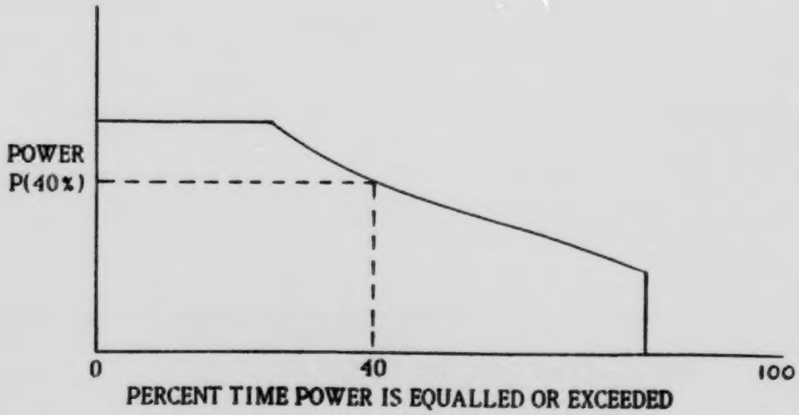

FIG. 6 **POWER EQUALLED OR EXCEEDED 40% OF THE TIME**

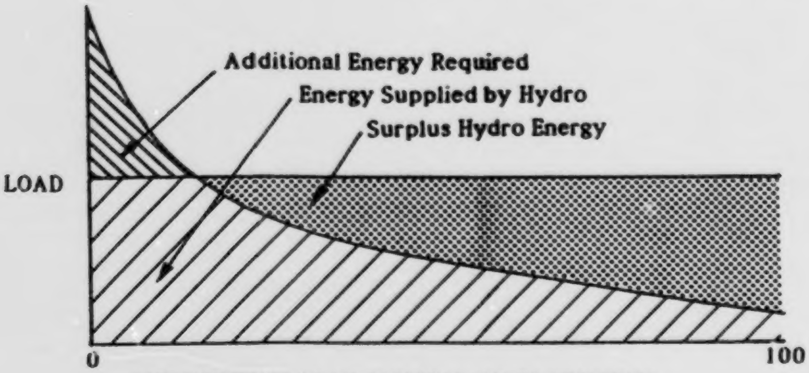

FIG. 7 **SUPERIMPOSITION OF THE DAILY POWER EQUALLED OR EXCEEDED 40% OF THE TIME ON THE DAILY LOAD-DURATION CURVE**

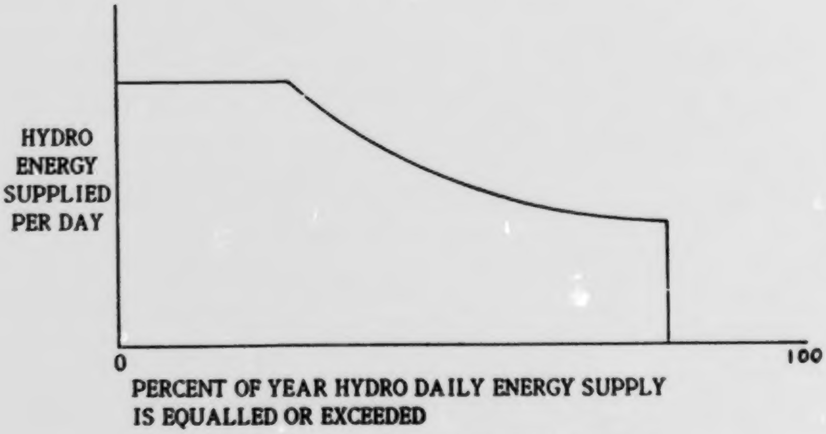

FIG. 8 **ENERGY SUPPLY DURATION CURVE**

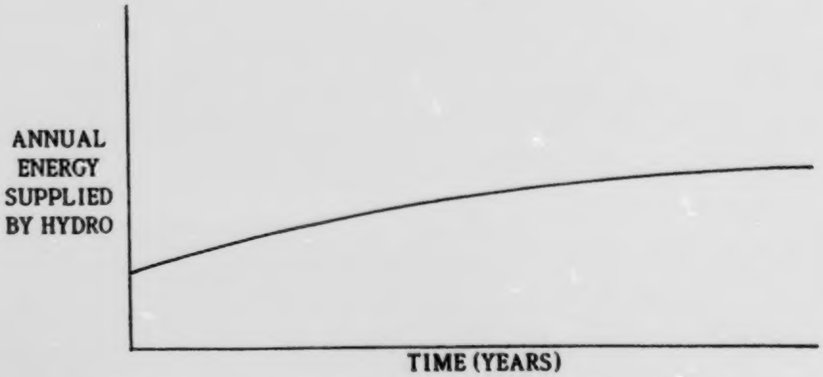

FIG. 9 **ENERGY SUPPLIED BY HYDRO vs TIME**

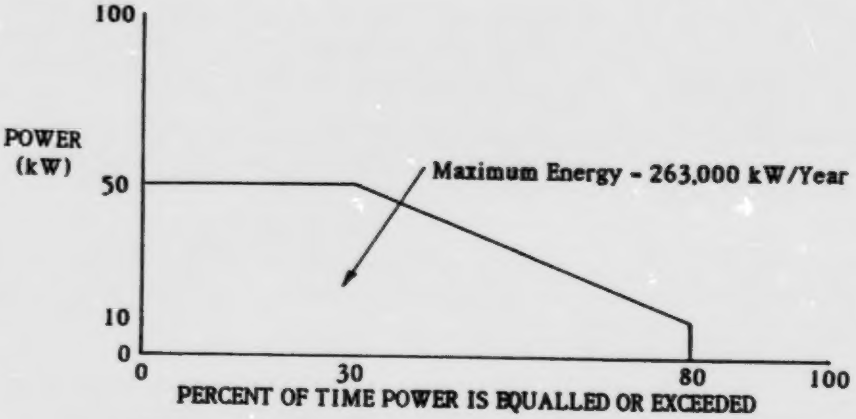

FIG. 10 **SIMPLIFIED POWER-DURATION CURVE (ANNUAL)**

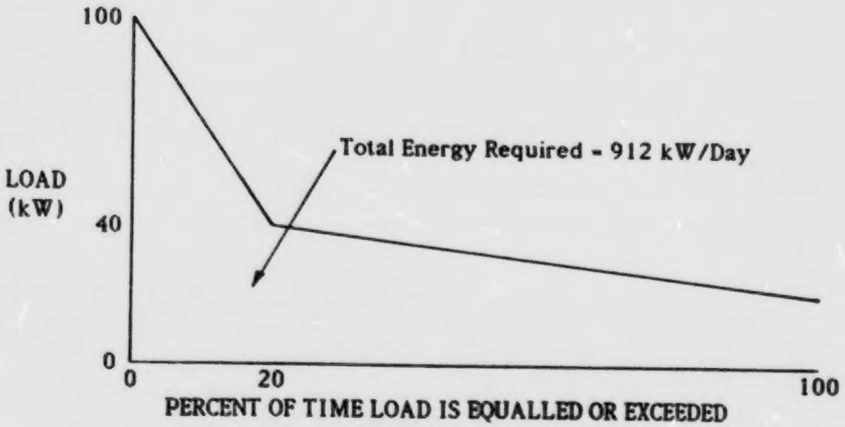

FIG. 11 **SIMPLIFIED LOAD-DURATION CURVE (DAILY)**

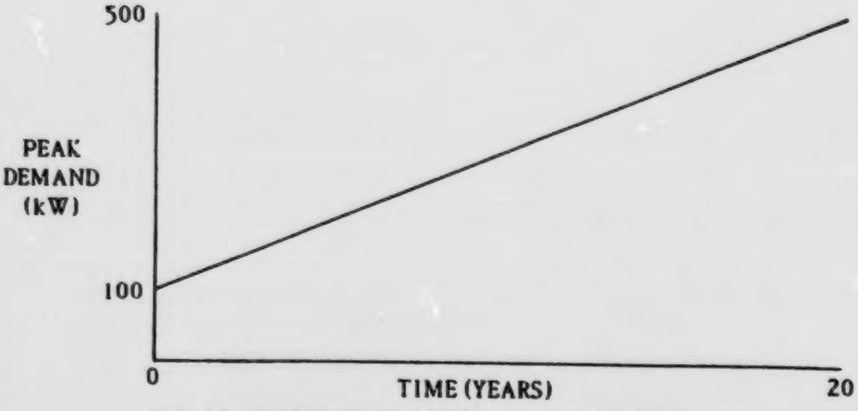

FIG. 12 **SIMPLIFIED PEAK DEMAND FORECAST**

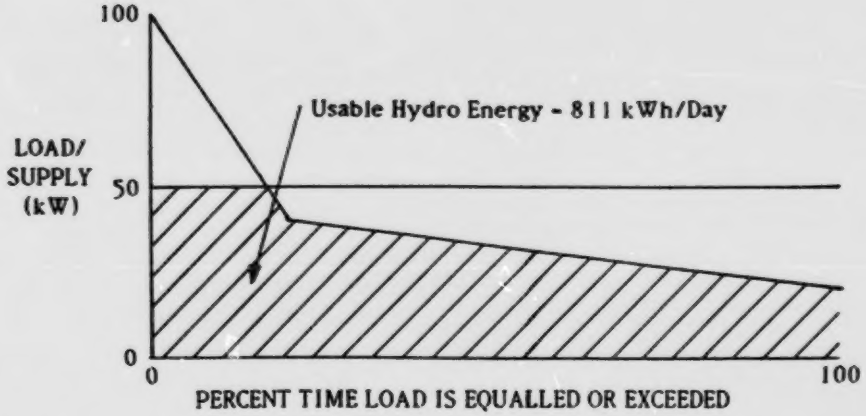

FIG. 13 **USABLE HYDRO ENERGY FOR POWER EQUALLED OR EXCEEDED 0 - 30% OF THE TIME**

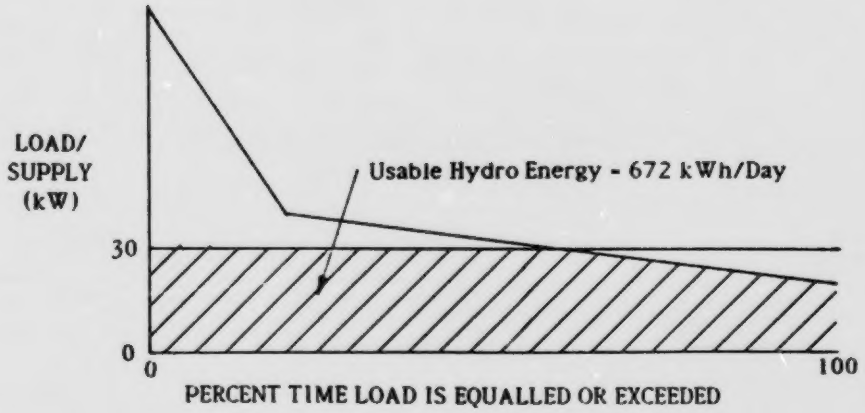

FIG. 14 **USABLE HYDRO ENERGY FOR POWER EQUALLED OR EXCEEDED 55% OF THE TIME**

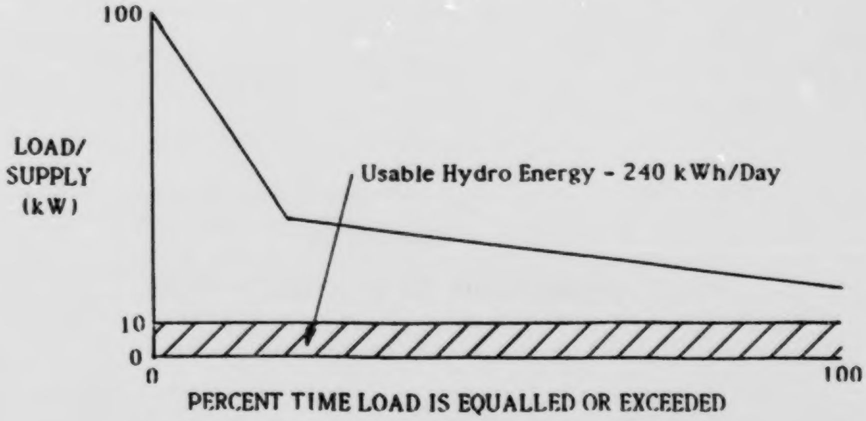

FIG. 15 **USABLE HYDRO ENERGY FOR POWER EQUALLED OR EXCEEDED 80% OF THE TIME**

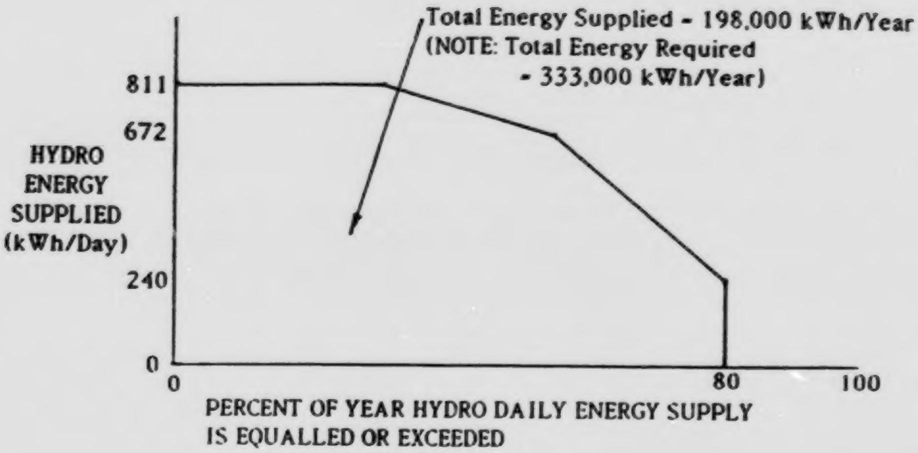

FIG. 16 **ENERGY SUPPLY DURATION CURVE AT TIME OF COMMISSIONING**

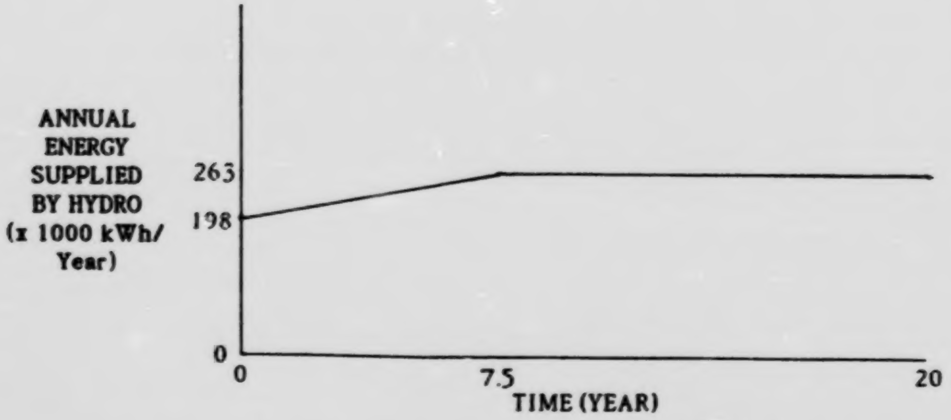

FIG. 17 **ENERGY SUPPLIED BY HYDRO vs TIME**

SESSION 8:

COMPUTER ANALYSIS

Chairperson: B. Robin
Cumming, Cockburn Ltd.

Waterhammer Computations for Small Hydro

By
J.S. Gulliver, P.V. Awate

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Waterhammer Computations for Small Hydro

by John S. Gulliver and Prakash V. Awate

When the preliminary layout and hydraulic parameters of a hydropower facility are selected, an analysis for waterhammer and other pressure surges caused by various possible operating conditions must often be conducted. One may spend a significant amount of time writing a computer program to suite the actual situation. A menu–driven microcomputer program, SURGE, for waterhammer analysis of various hydroplant arrangements, has been developed. The program is suitable for small hydropower in that it is designed to handle various hydroplant arrangements without altering the code. Thus, the waterhammer computations for a proposed facility may be accomplished quickly and at a low cost.

Introduction

Waterhammer is the pressure wave which occurs with a sudden change in penstock velocity i.e. valve closure or turbine load rejection at a hydroplant. Generally waterhammer pressure analysis is the calculation of pressures and velocities during an unsteady (transient) operational mode of a hydropower plant. Sometimes the waterhammer may cause dangerously high and low pressures. If these pressures are not within the prescribed limits, then the pipe system may be damaged, and hydropower plant forced to shut down. Therefore, the design engineer must always be aware of the problems which can be caused by transient operations.

The most basic equation of waterhammer analysis may be written as

$$\Delta H = \frac{-a\ \Delta V}{g} \qquad (1)$$

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where

ΔH = change in pressure head associated with a given pressure wave,
ΔV = change in velocity which caused the pressure wave, i.e.closing or opening a valve, closing or opening gates, load rejection, etc.
a = speed of sound in water, which is the waterhammer wave speed, and
g = acceleration of gravity.

Equation 1 indicates that the pressure head increases when the velocity is decreased, and vice versa. The waterhammer wave speed is between 300 m/sec and 1400 m/sec, depending upon the air content of the water, the relative wall thickness, wall elasticity, and the joint between the pipe sections. For relatively short conduits, the pressure wave has reached the end of the pipe and returned before a significant ΔV occurs, thus waterhammer is not a concern. Hydraulic transients are a potential problem if [Chaudhry, 1979]

$$\frac{LV}{H} > 10 \text{ ft/sec} \quad \text{or} \quad 3.3 \text{ m/sec} \tag{2}$$

where L = length of penstock,
V = flow velocity in penstock, and
H = net head.

Equation 2 is for a worst case situation such as near-instantaneous valve closure. If the conditions specified in Eq. 2 are met, one needs to further investigate the possibility of waterhammer problems. For very long conduits, a rapid change in velocity can create a significant waterhammer, and plant design must include some means of reducing these pressures such as a longer valve closure and opening times, surge tanks, pressure regulating valves, etc.

Methods for Controlling Waterhammer Pressures

To eliminate or reduce undesirable transients, such as excessive pressures, column separation and pump/turbine overspeed following power failure or load rejection–the following devices are used.

(1) Surge tanks
  a) Simple surge tank
  b) Orifice tank
  c) Differential (standpipe) surge tank
  d) Closed surge tank or air chamber

(2) Different types of valves
  a) Safety valves
  b) Pressure relief valves
  c) Pressures regulating valves
  d) Air-inlet valves
  e) Check valves

In addition, transients may be reduced by increasing penstock diameter or reducing waterhammer wave velocity, i.e. through entraining air or using a more flexible pipe. Some common devices to control waterhammer problems are shown in Fig. 1.

The Surge Computer Program

When the preliminary layout and parameters of the hydropower plant are selected, a great deal of analysis for waterhammer caused by various possible operating conditions must be conducted. One may spend a significant amount of time writing or adapting a computer program to suit the actual situation.

A microcomputer program for waterhammer analysis of various hydroplant arrangements has been developed on a IBM–PC. The program is highly interactive and user–friendly, so one does not need to be familiar with the code to use it. It is a compiled Microsoft Basic Program. The user needs the following devices to operate SURGE.

(a) An IBM Personal Computer with 128k bytes central memory
(b) A color monitor for the graphics (if graphic output is desired)
(c) A printer for output
(d) A PC–DOS 2.1 (or later version) to load the program

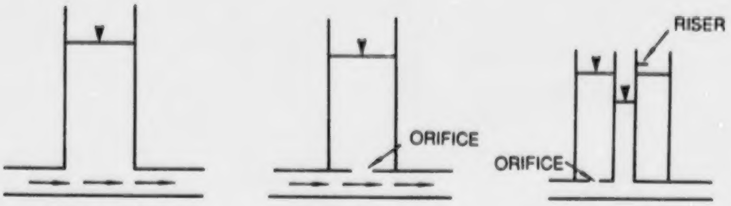
The program is designed to handle a variety of hydropower plant arrangements; the user only need change the input values, and the program can automatically solve various development schemes. There are six options incorporated, as shown in Fig. 2. In addition, various types of devices to reduce pressure transients are incorporated into the program. The user may choose a simple surge tank, a differential (standpipe) surge tank, or orifice surge tank, an air chamber, or a pressure regulating valve.

Turbine characteristics may be either input to the program or standard curves may be used if such information is not available. When there are no turbine characteristic curves available, the program provides three different ranges of general Francis turbine characteristic information [Willer, 1988], as shown in Fig. 3. The three ranges are:

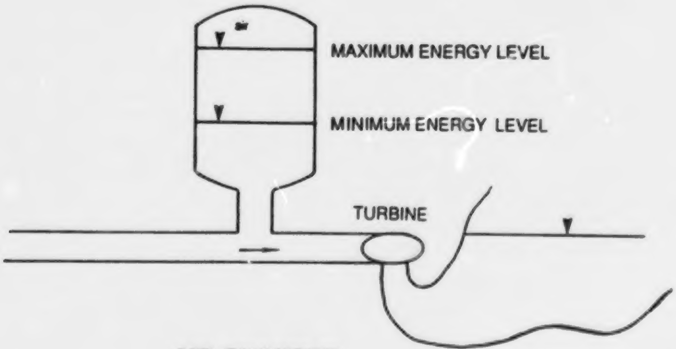
(a) $111 < n_s < 178$
(b) $178 < n_s < 214$
(c) $214 < n_s < 334$

where $n_s = n\sqrt{P_d}/H_d^{1.25}$ in which
n_s = design specific speed (metric units),
P_d = turbine output, kW, and
H_d = design head (m)

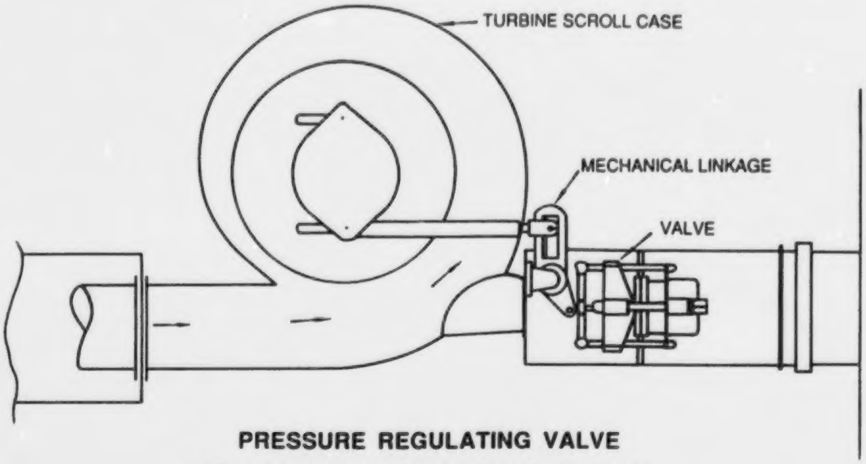
The input data are entered at the keyboard for the first run except specific Francis turbine characteristics (if desired). If the user wants to save these data for the next calculation, they may be stored under a file name on the floppy disk. The specific turbine characteristics may be prepared in advance, and stored in a data file which is named by the user.


RISER
ORIFICE
ORIFICE

SIMPLE TANK **ORIFICE TANK** **DIFFERENTIAL TANK**


MAXIMUM ENERGY LEVEL
MINIMUM ENERGY LEVEL
TURBINE

AIR CHAMBER


TURBINE SCROLL CASE
MECHANICAL LINKAGE
VALVE

PRESSURE REGULATING VALVE
WITH MECHANICAL LINKAGE TO WICKET GATES

Fig. 1. Common devices for control of waterhammer.

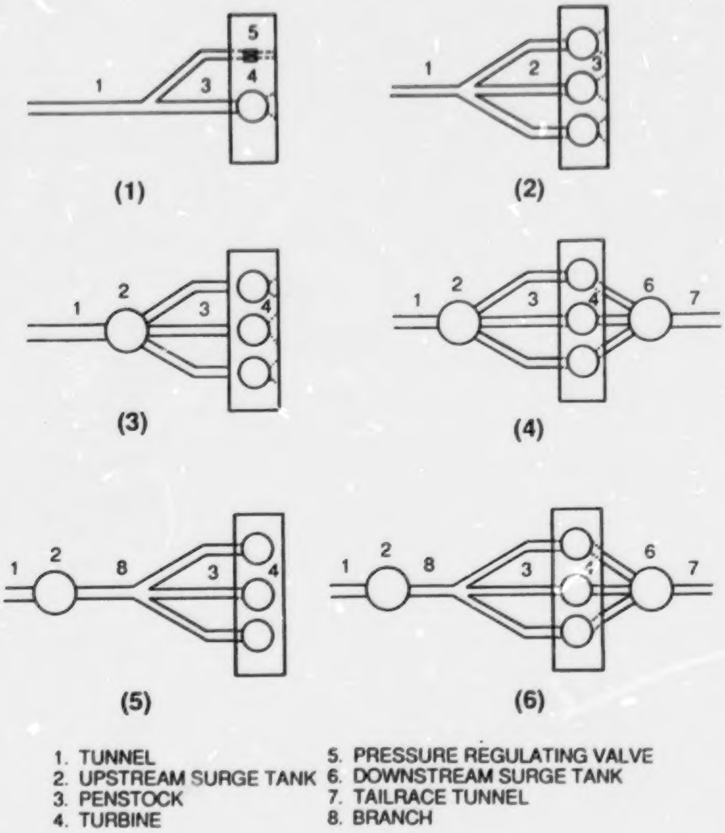

5
1
3
4
(1)
1
2
3
(2)
1
2
3
4
(3)
1
2
3
4
6
7
(4)
1
2
8
3
4
(5)
1
2
8
3
4
6
7
(6)
1. TUNNEL
2. UPSTREAM SURGE TANK
3. PENSTOCK
4. TURBINE
5. PRESSURE REGULATING VALVE
6. DOWNSTREAM SURGE TANK
7. TAILRACE TUNNEL
8. BRANCH

Figure 2. Surge options for hydroplant arrangement.

After computations are complete, the following information may be obtained.

a) Input data list (optional) – SURGE may print the input data, if desired.

b) Head and discharge vs. distance values may be printed and displayed on the monitor.

c) Head and discharge vs. time at a given location may be printed out and displayed on the monitor. There are four options for the location of the curves:

   1) At the upstream of surge tank (if existing)
   2) Immediately before the turbines
   3) At the downstream surge tank
   4) Immediately before turbine and pressure regulating valve.

d) The rotational speed of the turbine vs time.

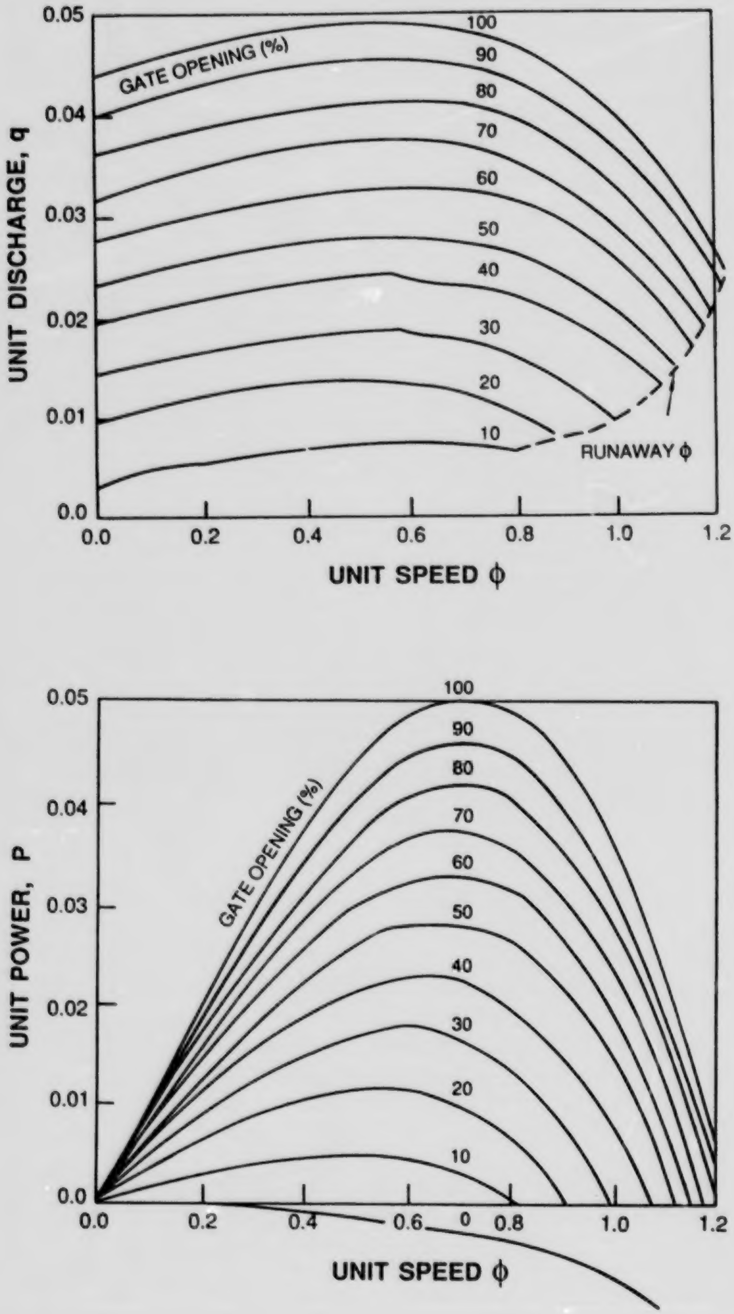


Fig. 3. General Francis turbine characteristics included in SURGE.

Test Problem (Rubi Mine Hydroelectric Plant)

The profile of the pipeline of Rubi Mine hydroelectric project located in Mining, U.S.A. is shown in Fig. 4. It was desired to eliminate or handle waterhammer pressures at minimum cost.

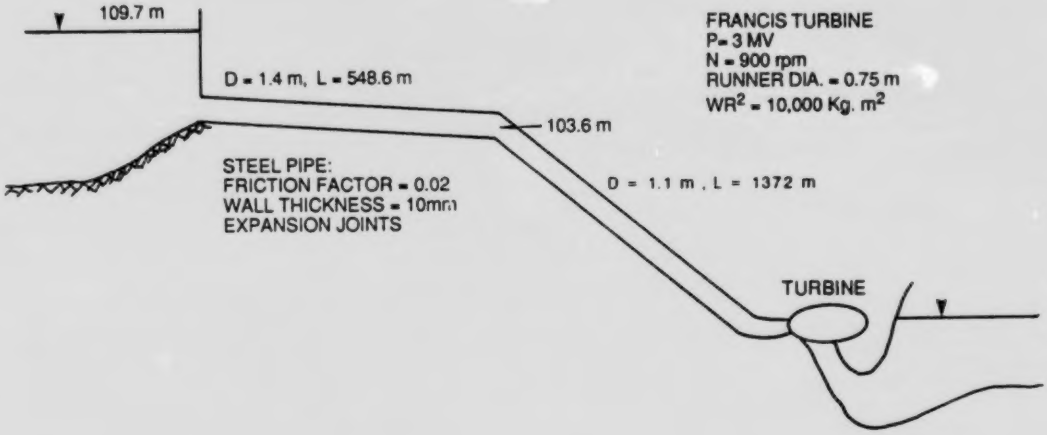


Fig. 4. Layout of Rubi Mine Project

The preliminary design of the pipeline consists of an upstream tunnel section (1.4 m diameter and 549 m in length) and penstock (1.1 m diameter and 137 m in length). At the end, there is proposed one Francis turbine rated at 3 MW and 109.7 m gross head. The maximum discharge is 3.68 m^3/s with turbine diameter 0.75 m, rotational speed 900 rpm and wr^2 of 10,000 kg–m^2. The elevation of the junction between the tunnel and penstock is 103.6 above the tailwater.

The vapor pressure of water is at approximately –32 ft of head, assuming atmospheric pressure is zero. Water column separation will occur if the pipe pressure approaches vapor pressure. Pressure at the junction is head–103.6. If this value is negative, there is vacuum in pipes at the junction. For all the options considered, the head at the junction never goes below 103.6 m, indicating that pressure is always positive in the system. The reason for this is the relatively long governor closure time of 20.0 sec during load rejection, versus the approximately 4 sec it takes for a pressure wave to reach the reservoir and return to the turbine.

Cost analysis for all the options is done for achieving the best solution with minimum cost. Costs were found from cost curves [Willer, 1988], from contacting equipment suppliers, and from prior experience. A thicker, more expensive penstock is required for high design pressures.

As the penstock diameter is increased, headloss will be reduced and benefits of additional head are increased. The additional power from this additional head is then computed. the benefits due to the reduction of headloss are assumed to be

$2000 USA per kW of additional power. Therefore the effective cost is equal to the total cost of the penstock system plus components required to reduce waterhammer pressures minus the benefit due to a reduction in headlosses.

The options studied and the results generated by SURGE and the cost computations are given in Table 1. Figure 5 gives the result shown on the graphics screen for Case No. 1a, without a pressure controlling device. A pressure regulating valve just upstream of the turbine with typical lag time of 0.4 sec and linear gate openings was very successful. Maximum pressure rise is 26.5% and increase in rotational speed is 24.2% over the steady-state condition for all the three options with a pressure regulating valve. The head and discharges for Case No. 3b are shown in Fig. 6. A simple surge tank located at the junction of tunnel and penstock

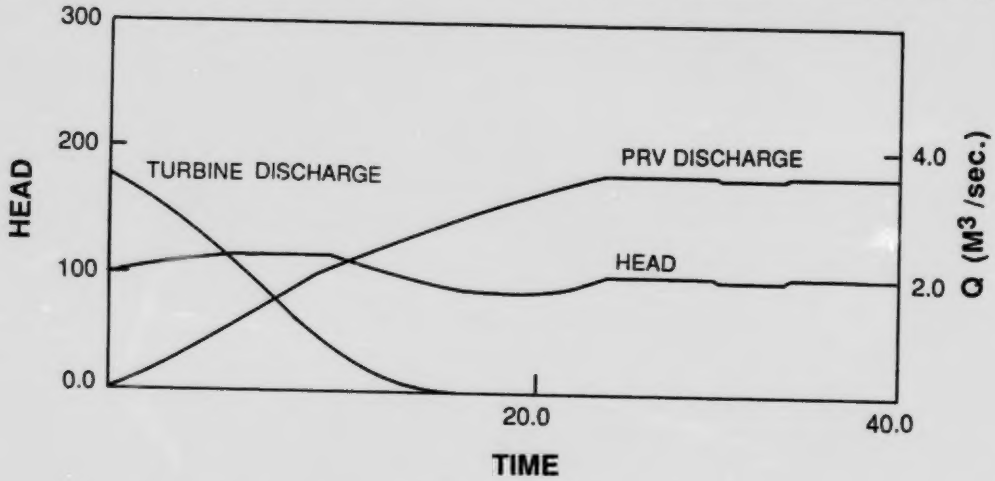


Fig. 5. Graphic output of SURGE for Case No. 1a, 1.1 m diameter penstock without pressure regulating device.

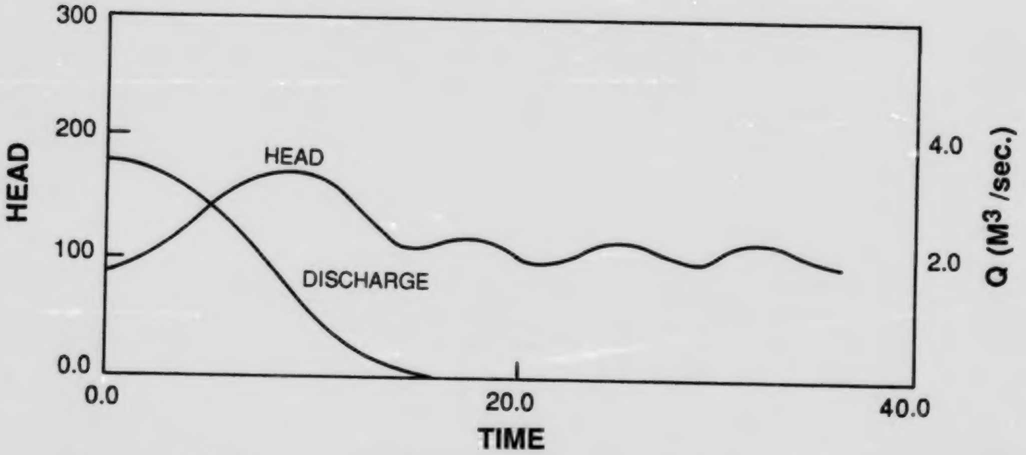


Fig. 6. Graphic output of SURGE for Case No. 3b, 1.3 m penstock diameter with a pressure regulating valve.

resulted in a more costly installation. Surge tank location was chosen such that an extremely tall structure would not need to be built. Options 1c and 2c with cross-sectional area 50 m^2 was not overly beneficial as the pressure rise is not reduced substantially. While for option 3c with smaller cross-sectional area (10 m^2) the pressure rise is reduced from 59.6% (without surge tank) to 43.9%. An air chamber just upstream, i.e. 100 m from turbine with cross-sectional area 100 m^2 and air volume from 500 m^2 to 200 m^2 also reduces pressure rise considerably.

Among all the pressure regulating devices or techniques studied herein, it can be seen from Table 1 that the pressure regulating valve is the best device for the Rubi Mine Hydroelectric Plant. It is clear from Table 1 that options 2b and 3b i.e. penstock diameter 1.2 m with pressure regulating valve and penstock diameter 1.3 m with pressure regulating valve are the best solutions among the options studied.

Conclusions

1) SURGE is an user-friendly and menu driven computer program. The user need only follow the prompts of each screen.

2) Three ranges of turbine specific speed have been stored in the program for planning and preliminary design. Therefore users who do not have the turbine characteristics information can still use SURGE to solve the transients problems.

3) SURGE can solve different waterhammer problems with or without any pressure controlling device, without any modifications to the program.

4) SURGE can graph the computed results on the color monitor, and also print test results.

5) SURGE was used successfully to choose a cost effective preliminary design for the Rubi Mine hydroelectric Plant. The best solutions (of 13 options) for the Rubi Mine Hydroelectric Plant are penstock diameter 1.2 m with pressure regulating valve and penstock diameter 1.3 m with pressure regulating valve.

References

1. Chaudhry, M. H., *Applied Hydraulics Transients*, Van Nostrand Reinhold, 1979.

2. Willer, D., "Powerhouse Design and Small Hydro Project Cost Estimates," Ch. 7 in Gulliver, J. S. and Arndt, R.E.A., *Hydropower Engineering Handbook*, McGraw-Hill, 1988.

Acknowledgements

This program was written under a grant from the IBM Corporation to the Civil and Mineral Engineering Department, University of Minnesota. The second author was funded by a United Nations Fellowship while on leave from the Central Water and Power Research Station, Pune, India.

TABLE I. SUMMARY RESULTS OF WATERHAMMER ANALYSIS

Case No.	Penstock diameter	Pressure controlling device	Design Head	Maximum pressure		Rotational speed		Total Cost Penstock System	Effective Cost Penstock System
				(m)	(% increase)	(rpm)	(% increase)	(mill $)	(mill $)
1a	1.1 m	None.	88.4	175.9	99.0	1225	36.1	2.80	2.80
1b	1.1 m	Pressure regulating valve.	88.4	111.8	26.5	1118	24.2	2.30	2.30
1c	1.1 m	Simple surge tank. (Area = 50 m^2)	88.4	157.0	77.6	1204	33.8	2.70	2.70
1d	1.1 m	Air chamber. (Area = 100 m^2) (Air volume = 300 m^3)	88.4	132.1	49.5	1091	21.2	2.58	2.58
2a	1.2 m	None.	95.1	166.5	75.1	1209	34.3	3.05	2.62
2b	1.2 m	Pressure regulating valve.	95.1	115.4	21.4	1119	24.3	2.61	2.18
2c	1.2 m	Simple surge tank. (Area = 50 m^2)	95.1	149.0	56.7	1187	31.9	2.96	2.53
2d	1.2 m	Air chamber. (Area = 100 m^2) (Air volume = 300 m^3)	95.1	140.5	47.7	1096	21.8	2.93	2.50
3a	1.3 m	None.	99.2	158.3	59.6	1191	32.3	3.27	2.57
3b	1.3 m	Pressure regulating valve.	99.2	117.0	18.0	1114	23.8	2.88	2.18
3c	1.3 m	Simple surge tank. (Area = 10 m^2)	99.2	142.7	43.9	1168	29.8	3.13	2.43
3d	1.3 m	Air chamber. (Area = 100 m^2) (Air volume = 200 m^3)	99.2	147.9	49.1	1099	22.1	3.24	2.54
4a	1.4 m	None.	101.7	151.8	49.2	1177	30.8	3.59	2.73

Small Hydro Analysis and Reporting Program

By
G. Steeves, B. Robin

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Small Hydro Analysis and Reporting Program

G. L. Steeves[1] & B. Robin[2]

The development of a viable small hydro industry is based on the efficient utilization of both physical and social resources. The physical resources of Ontario are its numerous rivers and waterfalls. The social resources are the ability of the private sector and the government to economically evaluate the hydraulic resources and development costs of the individual sites.

The need to develop a minimum standard of "screening" or "prefeasibility report" was recognized by the Ministry of Energy. To facilitate this objective and provide a common base for the completion of prefeasibility reports, the Ministry undertook the development of a Small Hydro Analysis and Reporting Program (SHARP). This program would have as its primary objectives:

(1) standardization of prefeasibility reports
(2) provision of small hydro analysis tools to users
(3) consolidation of all existing studies in a uniform data base
(4) development of a uniform hydrologic data base

Secondary objectives of the program were to provide:

(5) interactive tutorial features
(6) the ability to utilize individual functions
(7) installation on portable personal computers for use on remote sites

CURRENT SCOPE OF SHARP

The basic program has two data bases and develops a prefeasibility report incorporating the following.

(1) Site inspection report
(2) Hydrologic analysis
(3) Hydraulic analysis
(4) Turbine analysis and selection
(5) Cost estimates
(6) Economic analysis
(7) Barriers to development

---

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[2] Cumming Cockburn Limited, 145 Sparks Avenue, Willowdale, Ontario M2H 2S5

FUTURE ENHANCEMENTS

(1) Detailed tutorials
(2) Data handling improvements
(3) Problem sets/Demo disk
(4) Optimization routines
(5) Detailed users manual

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SCOPE OF SHARP

The basic program has two data bases and develops a prefeasibility report incorporating the following.

(1) site inspection report
(2) hydrologic analysis
(3) hydraulic analysis
(4) turbine analysis and selection
(5) cost estimates
(6) economic analysis
(7) barriers to development

SHARP was developed using "Turbo-Pascal" due to its programming structure, ease of maintenance, windowing facilities, etc.

FUTURE ENHANCEMENTS

SHARP is being updated on a continuing basis. Present planned future enhancements include:

(i) Improving data handling, specifically the importation of external data.

(ii) Development of problem sets and a disk drive.

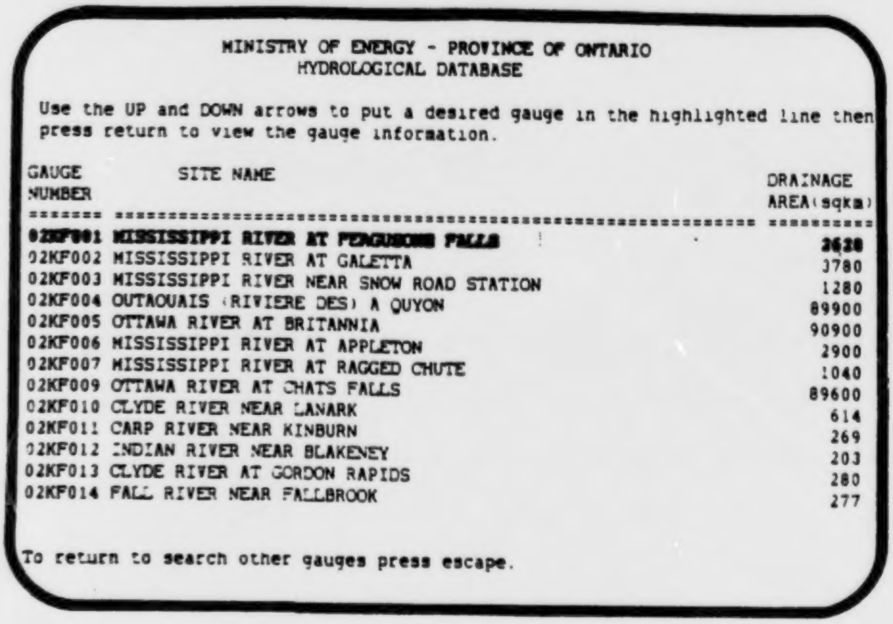
(iii) Incorporation of a variety of optimization routines.

(iv) Preparation of a detailed users manual.

HYDROLOGICAL DATA BASE

The Water Survey of Canada currently operate and maintain over 600 stream flow gauges in the Province of Ontario. The daily flow data for the period of record for each of the gauges was obtained and analysed to produce annual flow duration curves as well as monthly 50 percent exceedance flows.

This data was then installed on an easily accessible data base. Ontario is divided into a system of watersheds and the user simply inputs the watershed code and the program presents the guages within that watershed (Figure 1).

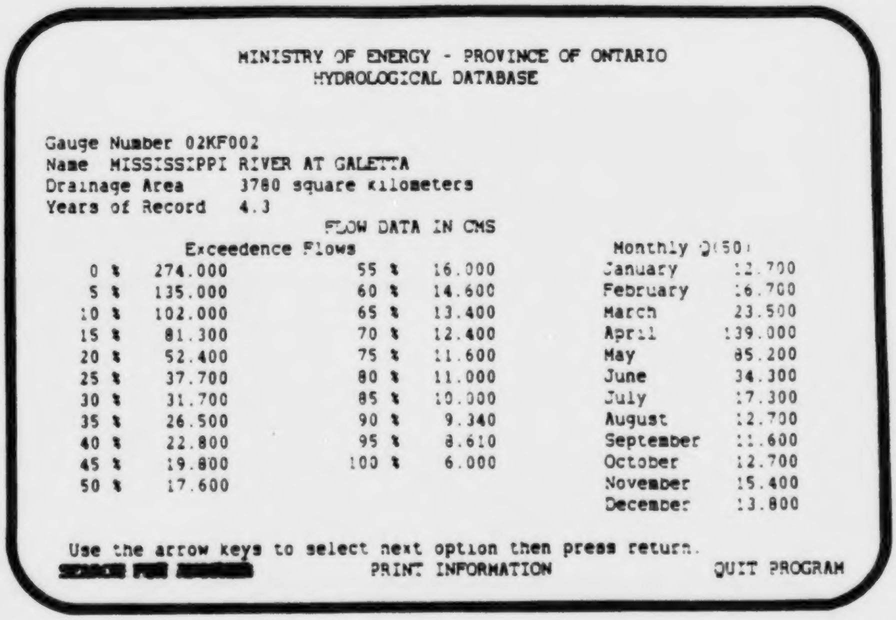


```
                 MINISTRY OF ENERGY - PROVINCE OF ONTARIO
                        HYDROLOGICAL DATABASE

 Use the UP and DOWN arrows to put a desired gauge in the highlighted line then
 press return to view the gauge information.

GAUGE          SITE NAME                                               DRAINAGE
NUMBER                                                                 AREA(sqkm)
======= ============================================================== ==========
02KF001 MISSISSIPPI RIVER AT FERGUSONS FALLS                                 2620
02KF002 MISSISSIPPI RIVER AT GALETTA                                         3780
02KF003 MISSISSIPPI RIVER NEAR SNOW ROAD STATION                             1280
02KF004 OUTAOUAIS (RIVIERE DES) A QUYON                                     89900
02KF005 OTTAWA RIVER AT BRITANNIA                                           90900
02KF006 MISSISSIPPI RIVER AT APPLETON                                        2900
02KF007 MISSISSIPPI RIVER AT RAGGED CHUTE                                    1040
02KF009 OTTAWA RIVER AT CHATS FALLS                                         89600
02KF010 CLYDE RIVER NEAR LANARK                                               614
02KF011 CARP RIVER NEAR KINBURN                                               269
02KF012 INDIAN RIVER NEAR BLAKENEY                                            203
02KF013 CLYDE RIVER AT GORDON RAPIDS                                          280
02KF014 FALL RIVER NEAR FALLBROOK                                             277

To return to search other gauges press escape.
```

Figure 1. Watershed Gauge Data

Upon selection of the appropriate gauge the specific flow data for that gauge is presented on the screen for review. The user then has the option to examine a second gauge and if desired have prints provided of the flow data for each gauge.

A planned enhancement is the provision of the years of record for a gauge in addition to the drainage area on Figure 1. This will facilitate the selection of an appropriate gauge for further analysis.

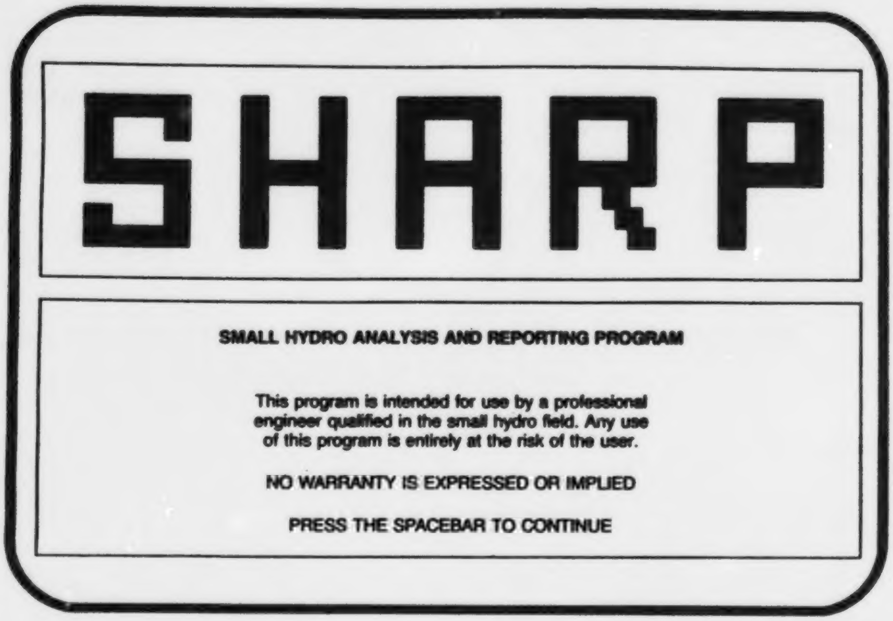


```
                  MINISTRY OF ENERGY - PROVINCE OF ONTARIO
                          HYDROLOGICAL DATABASE


Gauge Number 02KF002
Name  MISSISSIPPI RIVER AT GALETTA
Drainage Area      3780 square kilometers
Years of Record   4.3
                            FLOW DATA IN CMS
            Exceedence Flows                               Monthly Q(50)
    0 %   274.000             55 %   16.000            January      12.700
    5 %   135.000             60 %   14.600            February     16.700
   10 %   102.000             65 %   13.400            March        23.500
   15 %    81.300             70 %   12.400            April       139.000
   20 %    52.400             75 %   11.600            May          85.200
   25 %    37.700             80 %   11.000            June         34.300
   30 %    31.700             85 %   10.000            July         17.300
   35 %    26.500             90 %    9.340            August       12.700
   40 %    22.800             95 %    8.610            September    11.600
   45 %    19.800            100 %    6.000            October      12.700
   50 %    17.600                                      November     15.400
                                                       December     13.800

  Use the arrow keys to select next option then press return.
SEARCH FOR ANOTHER              PRINT INFORMATION                 QUIT PROGRAM
```

Figure 2. Individual Gauge Data

SMALL HYDRO ANALYSIS AND REPORTING PROGRAM (SHARP)

SHARP is a user friendly sequenced menu driven program. Within the program there are four levels of menus. The initiation of program prompts the first screen Figure 3.



SHARP

SMALL HYDRO ANALYSIS AND REPORTING PROGRAM

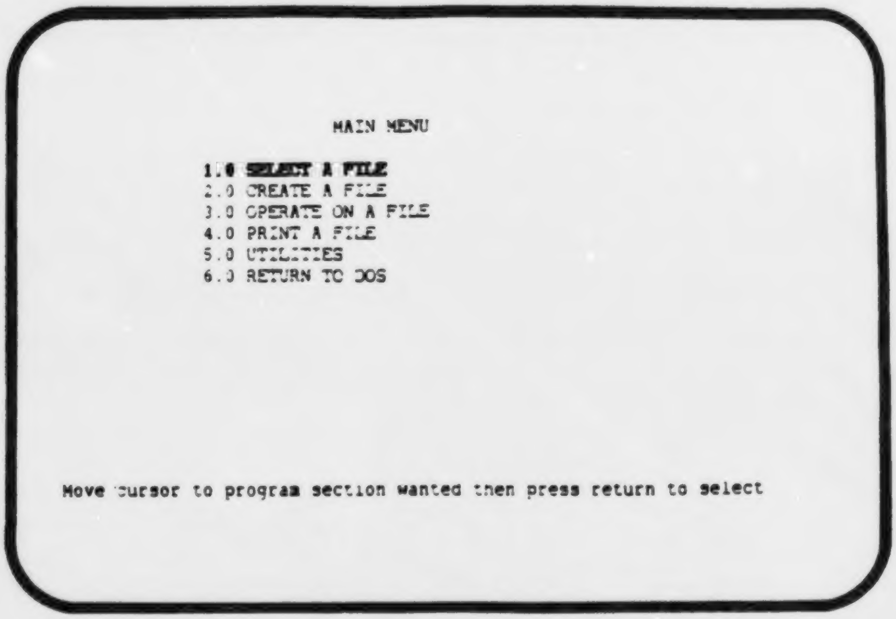
This program is intended for use by a professional engineer qualified in the small hydro field. Any use of this program is entirely at the risk of the user.

NO WARRANTY IS EXPRESSED OR IMPLIED

PRESS THE SPACEBAR TO CONTINUE

Figure 3.

The first menu in the layered menu system is the main menu. The core of the program is the use of the cursor control arrows to move around the individual screens.



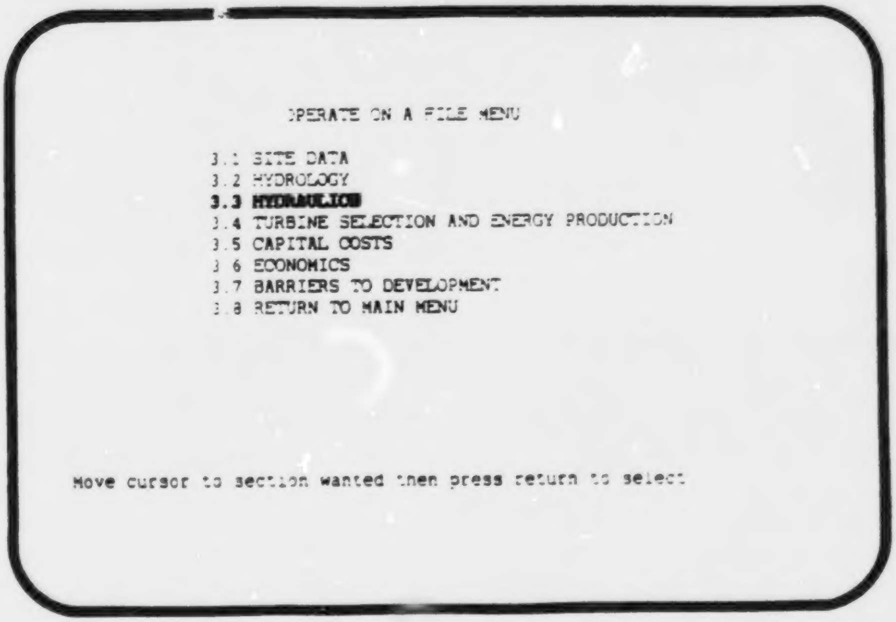
MAIN MENU

1.0 SELECT A FILE
2.0 CREATE A FILE
3.0 OPERATE ON A FILE
4.0 PRINT A FILE
5.0 UTILITIES
6.0 RETURN TO DOS

Move cursor to program section wanted then press return to select

Figure 4. Main Menu

Upon selection of an existing file or creation of a new file the program progresses to the operating menu.



```
OPERATE ON A FILE MENU

3.1 SITE DATA
3.2 HYDROLOGY
3.3 HYDRAULICS
3.4 TURBINE SELECTION AND ENERGY PRODUCTION
3.5 CAPITAL COSTS
3.6 ECONOMICS
3.7 BARRIERS TO DEVELOPMENT
3.8 RETURN TO MAIN MENU

Move cursor to section wanted then press return to select
```

Figure 5. Operate on a File Menu

Of the seven specific elements of the program, five have analytical capabilities and two are simply data storage facilities. Remembering the multiple objectives of the program there are specific sections which are redundant if the program has been utilized simply to analyse a specific turbine's performance and energy generation, economic analysis, hydraulics, etc.

In each of the following screens help is available on the form of a promptor.

F_1
Help Shows the command list.

F_2
Tutor Access the tutorial page for the active field if available.

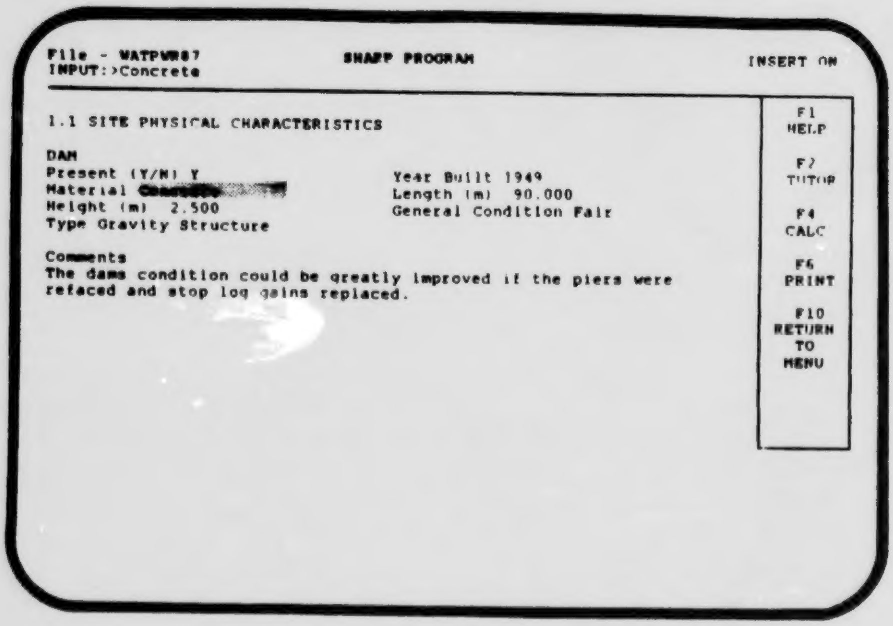
F_4
Calc Calculates all the values on the page.

F_6
Print Prints the current page.

SITE DATA

The site data section provides for the entry of site specific data including written text for existing or planned elements of the project. As you proceed through the program it is initiated by the recording of existing conditions and equipment which can be subsequently modified. Specific elements are:

Dam	Equipment - Turbines
Headrace	- Generator
Tailrace	- Gearbox
Trashrack	- Governors
Penstock	- Switchgear
Powerhouse	

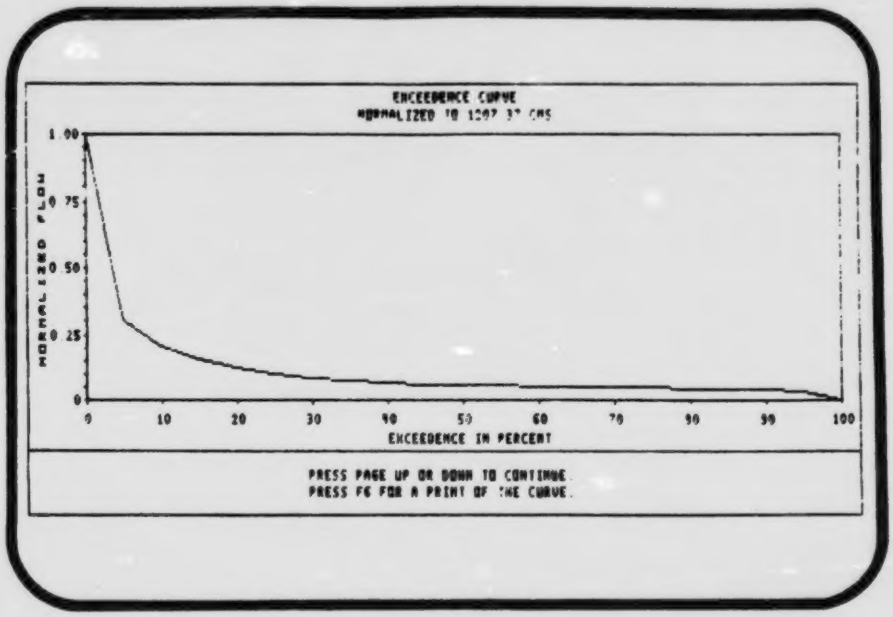


```
File - WATPWR87                SHARP PROGRAM                      INSERT ON
INPUT:>Concrete

1.1 SITE PHYSICAL CHARACTERISTICS

DAM
Present (Y/N) Y                        Year Built 1949
Material Concrete                      Length (m)  90.000
Height (m)  2.500                      General Condition Fair
Type Gravity Structure

Comments
The dams condition could be greatly improved if the piers were
refaced and stop log gains replaced.
```

Figure 6. Site Physical Characteristics

HYDROLOGY

The hydrology section allows for the integration of various gauges on developing a flow duration curve. That is it will numerically combine the date from various gauges as directed by the user, allow the utilization of a representative regional gauge, etc.


EXCEEDENCE CURVE
NORMALIZED TO 1207.37 CMS
NORMALIZED FLOW
1.00
0.75
0.50
0.25
0
0
10
20
30
40
50
60
70
80
90
100
EXCEEDENCE IN PERCENT

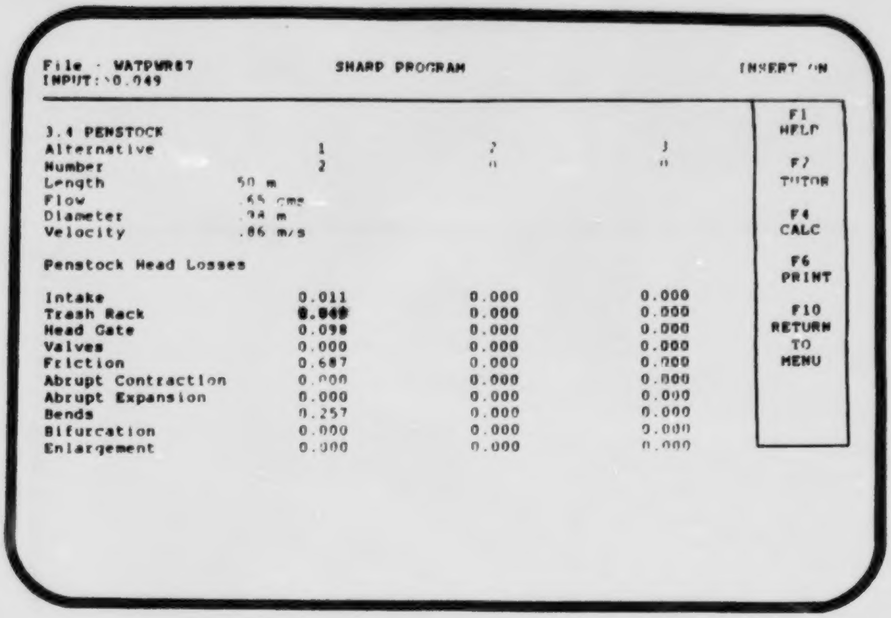
```
PRESS PAGE UP OR DOWN TO CONTINUE.
PRESS F6 FOR A PRINT OF THE CURVE.
```

Figure 7. Flow Duration Curve

This data is then transferred internally in the program to the various section where it is utilized, namely hydraulics and turbine selection. A user however is able to enter SHARP directly at these two sections inputting different data.

HYDRAULICS

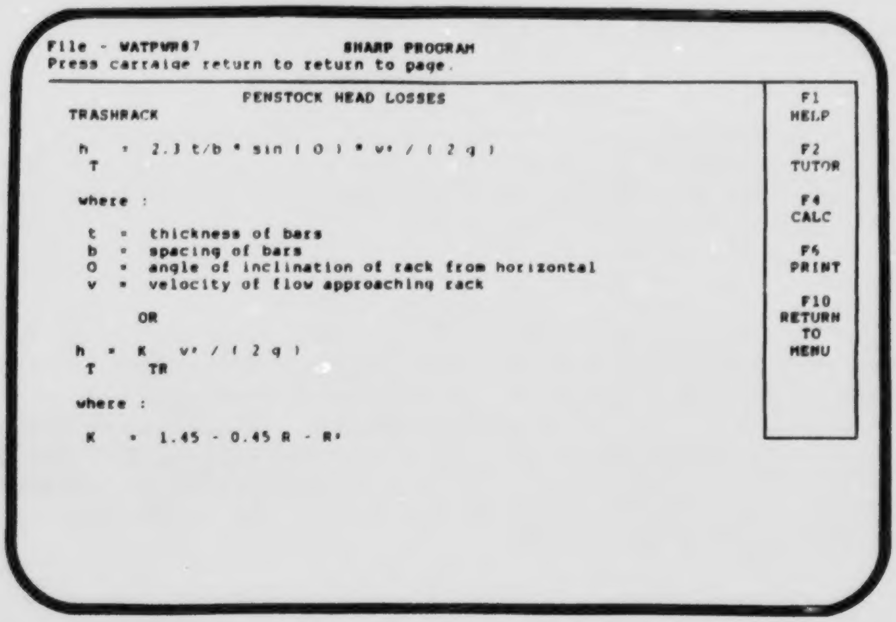
The hydraulics section has a data entry section which incorporates the total gross head, as well as variations in head pond and tailwater levels. The second portion of this section is capable of developing the shapes and dimensions of the hydraulic elements e.g. headrace, tailrace, penstocks, etc. and the ability to calculate the appropriate head losses. For example, let us look at penstock losses and penstock head losses.



```
File - WATPWR87                  SHARP PROGRAM                          INSERT ON
INPUT:>0.049
--------------------------------------------------------------------------------
                                                                       | F1    |
3.4 PENSTOCK                                                           | HELP  |
Alternative                    1             2             3           |       |
Number                         2             0             0           | F2    |
Length             50 m                                                | TUTOR |
Flow               .65 cms                                             |       |
Diameter           .98 m                                               | F4    |
Velocity           .86 m/s                                             | CALC  |
                                                                       |       |
Penstock Head Losses                                                   | F6    |
                                                                       | PRINT |
Intake                       0.011         0.000         0.000         |       |
Trash Rack                   0.049         0.000         0.000         | F10   |
Head Gate                    0.098         0.000         0.000         | RETURN|
Valves                       0.000         0.000         0.000         | TO    |
Friction                     0.687         0.000         0.000         | MENU  |
Abrupt Contraction           0.000         0.000         0.000         |       |
Abrupt Expansion             0.000         0.000         0.000         |       |
Bends                        0.257         0.000         0.000         |       |
Bifurcation                  0.000         0.000         0.000         |       |
Enlargement                  0.000         0.000         0.000         |       |
```

Figure 8. Penstock Head Losses

If we move the cursor to trashrack head losses and request F_2/Tutor, the following screen is displayed, the head loss calculated and manually inserted in the previous screen.



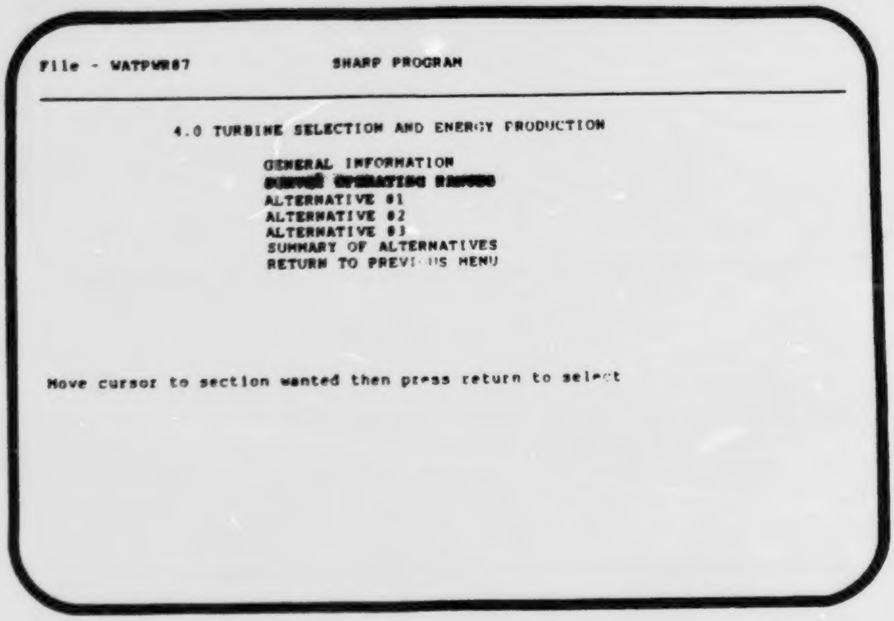
```
File - WATPWR87              SHARP PROGRAM
Press carraige return to return to page.
--------------------------------------------------------------------------------
                     PENSTOCK HEAD LOSSES                              | F1    |
 TRASHRACK                                                             | HELP  |
                                                                       |       |
  h   =  2.3 t/b * sin ( O ) * v² / ( 2 g )                            | F2    |
   T                                                                   | TUTOR |
                                                                       |       |
  where :                                                              | F4    |
                                                                       | CALC  |
   t  =  thickness of bars                                             |       |
   b  =  spacing of bars                                               | F6    |
   O  =  angle of inclination of rack from horizontal                  | PRINT |
   v  =  velocity of flow approaching rack                             |       |
                                                                       | F10   |
        OR                                                             | RETURN|
                                                                       | TO    |
  h  =  K    v² / ( 2 g )                                              | MENU  |
   T     TR                                                            |       |
                                                                       |       |
  where :                                                              |       |
                                                                       |       |
   K   =  1.45 - 0.45 R - R²                                           |       |
```

Figure 9. Penstock - Trashrack Head Losses

The result is the ability to examine the impact of various penstock sizes, etc. on the calculation of the net head and in subsequent sections, its impact on the overall project economies. The net head is automatically inserted in the following section.

TURBINE SELECTION AND ENERGY PRODUCTION

This section is the heart of SHARP. It allows a detailed preliminary evaluation of turbine types and specifically number and size of units.

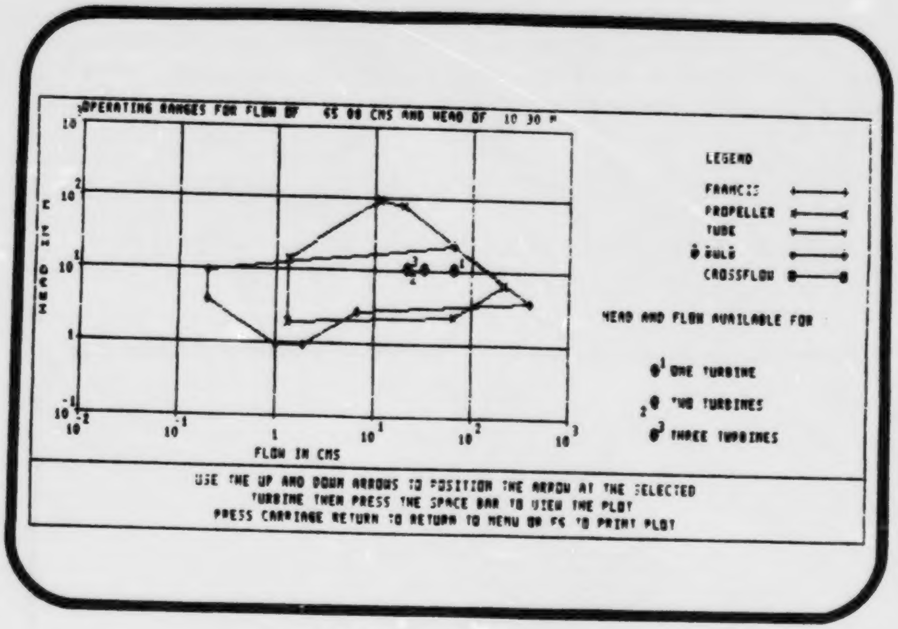


```
File - WATPWR87                SHARP PROGRAM
________________________________________________________________

           4.0 TURBINE SELECTION AND ENERGY PRODUCTION

                  GENERAL INFORMATION
                  SURVEY OPERATING RANGES
                  ALTERNATIVE #1
                  ALTERNATIVE #2
                  ALTERNATIVE #3
                  SUMMARY OF ALTERNATIVES
                  RETURN TO PREVIOUS MENU



Move cursor to section wanted then press return to select
```

Figure 10. Turbine Selection & Energy Production Menu

Under this menu General Information developed previously is available e.g. flows, net head.

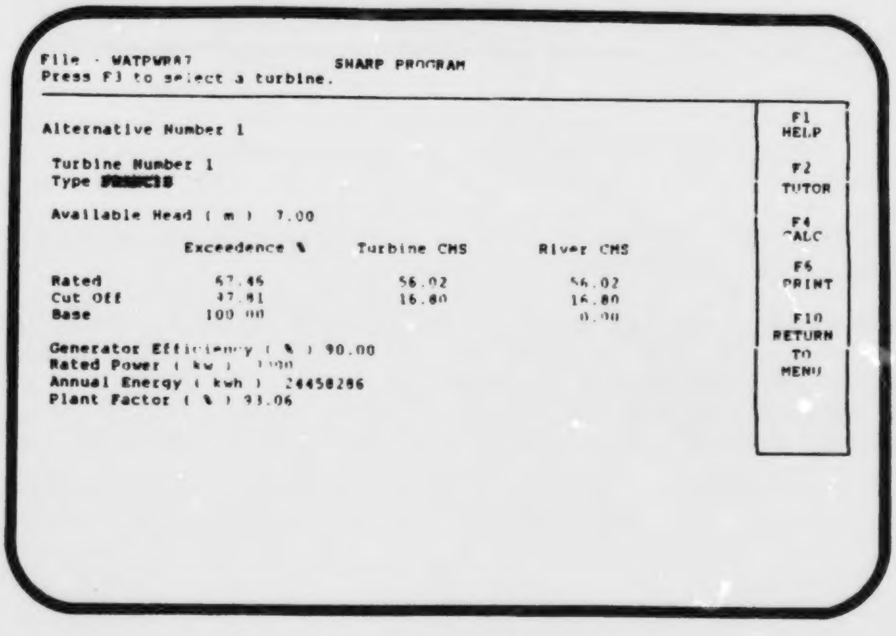
Under Survey Operating Ranges, the program defaults to the 50th percentile flow which is automatically displayed on a screen showing turbine operating ranges for up to three units. The user can examine on a single screen all the turbine types. To look at different plant flows the default value is simply overidden.


OPERATING RANGES FOR FLOW OF 65 00 CMS AND HEAD OF 10 30 M
HEAD IN M
FLOW IN CMS
10^{3}
10^{2}
10^{1}
1
10^{-1}
10^{-2}
10^{-1}
1
10^{1}
10^{2}
10^{3}
LEGEND
FRANCIS
PROPELLER
TUBE
BULB
CROSSFLOW
HEAD AND FLOW AVAILABLE FOR
1 ONE TURBINE
2 TWO TURBINES
3 THREE TURBINES

```
USE THE UP AND DOWN ARROWS TO POSITION THE ARROW AT THE SELECTED
TURBINE THEN PRESS THE SPACE BAR TO VIEW THE PLOT
PRESS CARRIAGE RETURN TO RETURN TO MENU OR F5 TO PRINT PLOT
```

Figure 11. Survey Operating Ranges

Under the examination of alternatives the user initiates the analysis by defining the number of units and minimum flow requirements. The analysis then proceeds to the working screen which allows the user to change almost any variable on the screen in examining the plant's operation. The user can look at an endless number of variables but the program will only maintain three files.

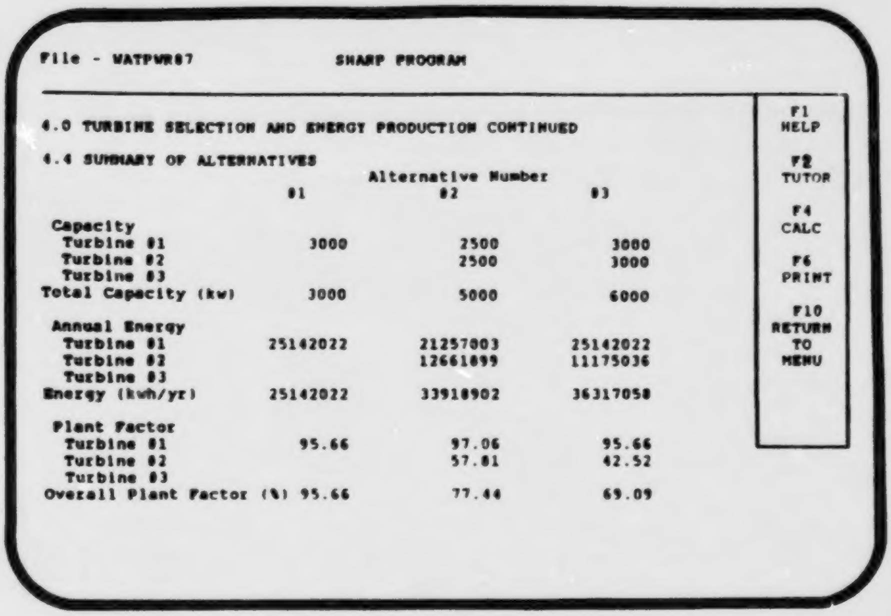


```
File - WATPWR87                SHARP PROGRAM
Press F3 to select a turbine.

Alternative Number 1

 Turbine Number 1
 Type FRANCIS

 Available Head ( m )  7.00

               Exceedence %     Turbine CMS        River CMS

 Rated             67.46           56.02             56.02
 Cut Off           97.81           16.80             16.80
 Base             100.00                              0.00

 Generator Efficiency ( % ) 90.00
 Rated Power ( kw )  3000
 Annual Energy ( kwh )  24458286
 Plant Factor ( % ) 93.06
```

F1
HELP
F2
TUTOR
F4
CALC
F5
PRINT
F10
RETURN
TO
MENU

Figure 12. Turbine Analysis & Energy Generation Screen

Upon completion of the alternatives the user can request an alternative summary screen displaying each of the alternatives and if necessary can return to the prior screen to evaluate an additional alternative.



```
File - WATPWR87                SHARP PROGRAM

4.0 TURBINE SELECTION AND ENERGY PRODUCTION CONTINUED

4.4 SUMMARY OF ALTERNATIVES
                                 Alternative Number
                        #1               #2               #3

 Capacity
  Turbine #1           3000             2500             3000
  Turbine #2                            2500             3000
  Turbine #3
Total Capacity (kw)    3000             5000             6000

 Annual Energy
  Turbine #1       25142022         21257003         25142022
  Turbine #2                        12661899         11175036
  Turbine #3
Energy (kwh/yr)    25142022         33918902         36317058

 Plant Factor
  Turbine #1          95.66            97.06            95.66
  Turbine #2                           57.81            42.52
  Turbine #3
Overall Plant Factor (%) 95.66         77.44            69.09
```

Figure 13. Summary of Alternatives

COST ESTIMATES

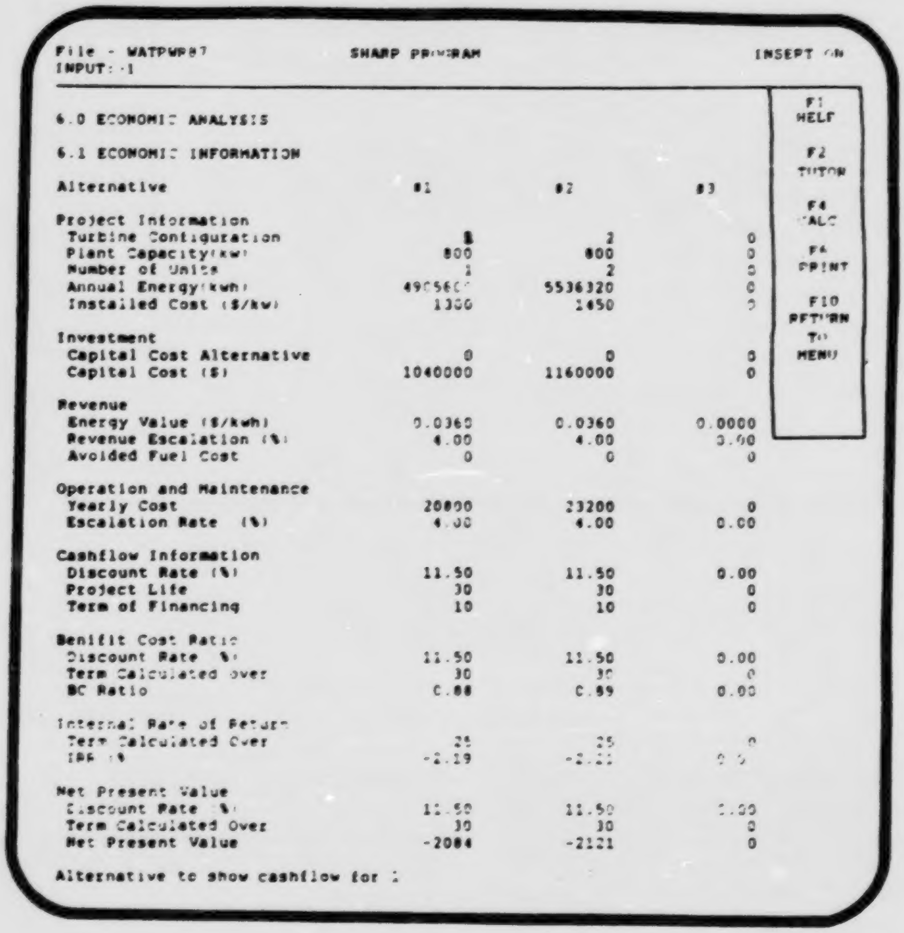
This section is simply a comprehensive capital cost schedule. It is intended to eventually expand the tutor features of this section to incorporate cost schedules, graphs, etc. Detailed costing guidelines are readily available in documents prepared in the United States and Canada. In the northern part of Ontario capital costs are so site specific it is difficult to develop representative cost curves. We are in the process of developing cost curves for unique items in small hydro projects.

The curve is accessed through F_2/Tutor and the cursor function allows the selection of the specific cost.

ECONOMICS

As with the turbine analysis the economic analysis uses "spread sheet concepts" in that it is only necessary to change certain variables and the program recalculates each of the economic factors. Sensitivities to energy values, revenue escalation, inflation discount rates are quickly established for NPV, IRR, B/C ratio, etc.

Unique features are incorporation of avoided energy costs, which we utilize in remote community applications.



```
File - WATPWR87                  SHARP PROGRAM                     INSERT ON
INPUT: 1

6.0 ECONOMIC ANALYSIS

6.1 ECONOMIC INFORMATION

Alternative                       #1             #2            #3

Project Information
 Turbine Configuration             1              2             0
 Plant Capacity(kw)              800            800             0
 Number of Units                   1              2             0
 Annual Energy(kwh)          4905600        5536320             0
 Installed Cost ($/kw)          1300           1450             0

Investment
 Capital Cost Alternative          0              0             0
 Capital Cost ($)            1040000        1160000             0

Revenue
 Energy Value ($/kwh)         0.0360         0.0360        0.0000
 Revenue Escalation (%)         4.00           4.00          0.00
 Avoided Fuel Cost                 0              0             0

Operation and Maintenance
 Yearly Cost                   20800          23200             0
 Escalation Rate  (%)           4.00           4.00          0.00

Cashflow Information
 Discount Rate (%)             11.50          11.50          0.00
 Project Life                     30             30             0
 Term of Financing                10             10             0

Benifit Cost Ratio
 Discount Rate (%)             11.50          11.50          0.00
 Term Calculated over             30             30             0
 BC Ratio                       0.88           0.89          0.00

Internal Rate of Return
 Term Calculated Over             25             25             0
 IRR (%)                       -2.19          -2.21          0.00

Net Present Value
 Discount Rate (%)             11.50          11.50          0.00
 Term Calculated Over             30             30             0
 Net Present Value             -2084          -2121             0

Alternative to show cashflow for 1
```

Figure 14. Economic Analysis

For the selected alternative the program is capable of generating detailed cash flows.

FUTURE ENHANCEMENTS

As SHARP is used continuously in our day-to-day practice, specific useful enhancements have been identified:

- (i) Allowing the integration of a specific manufacturers efficiency curve for energy analysis during a tender analysis.
- (ii) Develop plant size maximization routines relative to various criteria:
  - (a) Equipment & Powerhouse
  - (b) Water Passages & Intake, Penstock, etc.
  - (c) Transmission Line - Size & Distribution
  - (d) Dam, etc.
- (iii) Enhancing hydrology section to incorporate rainfall data, intensity curves, etc. with drainage area for utilization in developing countries.
- (iv) In hydraulics we would incorporate roughness, coefficients, penstock head losses, cost curves, etc. to allow optimization routines for penstock sizing.

CONCLUSION

SHARP has proven to be an invaluable design tool in our current practice. We are a smaller engineering firm specializing in micro, mini and small hydro projects. The versatility and expandability of SHARP has allowed us to consolidate approximately a dozen software packages used previously into a single device. It has also proved to be an effective educational tool training our junior engineers and technical staff.

This program development was only possible however through the financial assistance of the Ministry of Energy of the Province of Ontario.

Optimizing Turbine Selection and Plant Performance by Means of Computer Simulation of Model Turbine Characteristics

By
P.J. Jermann, P. Seguin

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OPTIMIZING TURBINE SELECTION AND PLANT PERFORMANCE BY MEANS OF COMPUTER SIMULATION OF MODEL TURBINE CHARACTERISTICS

P.J. Jermann *, P. Séguin **

Abstract

The paper outlines the B-spline approximation technique applied to numerical modelling of turbine model test results. The mathematical description of turbine characteristics allows for fast and efficient application of computer-integrated turbine selection programs to optimize plant energy production at the bid preparation stage. The paper presents the turbine selection process using the B-spline program system for the Port Dalhousie project, Canada's first two Pit turbines (4 MW each) located in St-Catharines, Ontario.

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1. Introduction

Except for standardized small hydro turbines with prefixed performance characteristics, the selection of turbine type, speed, diameter and setting is a custom designed process. This process is applied for each project to maximize performance, taking site specific headwater, tailwater and river flow duration data into account.

Since to date it has not been possible to simulate turbine performance by purely analytical means, any application of computer-integrated turbine selection programs is today still based on data which are "hand made", i.e. established exclusively by means of model testing. An efficient and integrated application of turbine selection programs requires therefore a complete and highly accurate mathematical description or numerical modelling of model tested turbine characteristics. Quite similar to the CNC machining task, the challenge for development engineers has rather been the modelling problem of shapes and surfaces rather than the computation program itself.

2. Approximation requirements

The application of simpler approximation methods like splines yields to results of relatively good smoothness provided that the curves or surfaces have steady curvatures. Unfortunately, measured turbine efficiency over turbine discharge for constant head - one of the most basic turbine characteristics - often shows "bumpy" parts (inflection points) due to dynamic phenomena (e.g. cavitation, draft tube instabilities, surge, etc.).

Furthermore, approximation methods must be flexible to describe the variety of model test results normally produced in a hydraulic laboratory. A description of a turbine performance consists of dependent variables such as efficiency, cavitation coefficient, etc. as function (surfaces) of two independent variables, typically head and discharge, with control parameters, such as wicket gate and runner blade opening.

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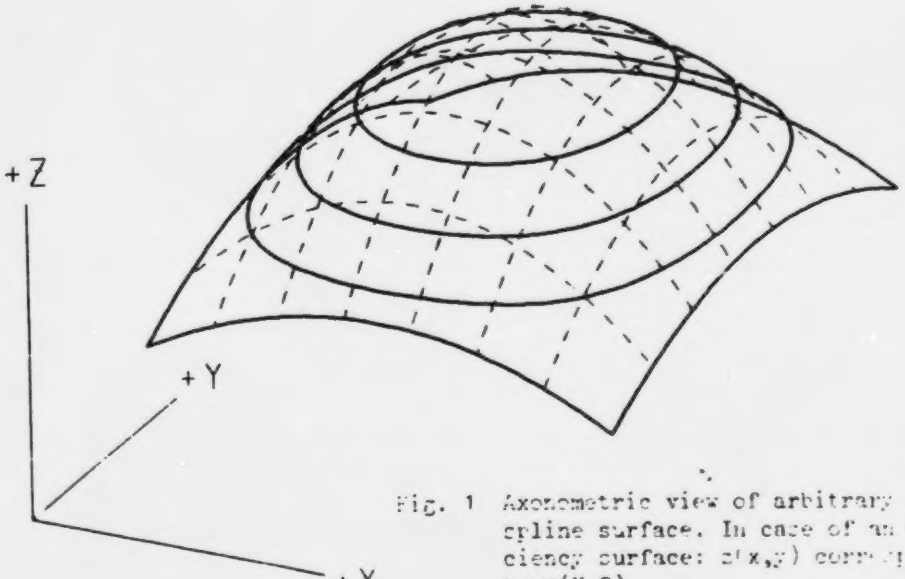

Fig. 1 Axonometric view of arbitrary B-spline surface. In case of an efficiency surface: $z(x,y)$ corresponds to $\eta(H,Q)$

Numerically modeled turbine characteristics must be transformable to be able to produce almost any kind of performance description, normally:

- transformation from model to prototype
- efficiency hill charts (fig. 1, fig. 5)
- performance curves, power or efficiency versus discharge for constant heads
- hill charts for fixed runner blade openings (propeller turbines) (fig. 3)
- hill charts for fixed wicket gate openings and adjustable runner blades

An efficient optimization of turbine performance based on numerically modeled turbine characteristics must further allow:

- interpolation of efficiency surfaces of two turbines with neighbouring specific speeds
- comparison of different model performances
- interpolation of intermediate propeller curves (fig. 4b)

3. Approximation by means of B-splines

DBS Escher Wyss implemented in 1986 the program system "BS" developed by Sulzer-Escher Wyss. This program meets all the above mentioned requirements. To represent measured turbine characteristic surfaces it uses B-spline approximations. B-splines are extended spline functions. Their degree of freedom is independent of the order which usually is between 3 and 5. A point P on a B-spline curve is represented by

$$P(u) = \sum_{i}^{n} V_i \, N_{i,k}(u)$$

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where V_i : vertices (or grid points)

n : number of vertices

$N_{i,k}$: i-th normalized B-spline of order k

u : parameter ($u_k \leq u \leq u_{n+1}$)

Similarly a point P on a surface is given by

$$P(u,v) = \sum_{j}^{m} \sum_{i}^{n} V_{i,j} N_{i,ku}(u) N_{j,kv}(v)$$

For mathematical details please refer to [1], [2].

The process of fitting a smooth and accurate surface through a series of measured points is solved in two steps:

1. Parameterization of curve / surface
2. Solution of linear least squares problem

The rather complex step of parameterization is facilitated by using the geometric meaning of vertices: grid points. Grid points (u-v coordinates) lie close to the surface, but not on it, and are always on its convex side. Surface parts with a high curvature use more vertices than others with a low curvature. A so-called grid generator is used for the approximate parameterization by locally adapting a grid refinement for areas with concentrated measuring points. This flexibility is very welcome since it means that the compromise between accuracy and smoothness can be controlled.

Given this method of solution, the quality - or accuracy - of the numerically modeled surface depends strongly on the arbitrarily determined grid points. Comparisons between approximated and measured function values can lead to a iterative refinement or adjustment of previously fixed grid points in view of a required approximation accuracy. Hence, approximation experience becomes quite important for a fast and efficient computation of turbine characteristics.

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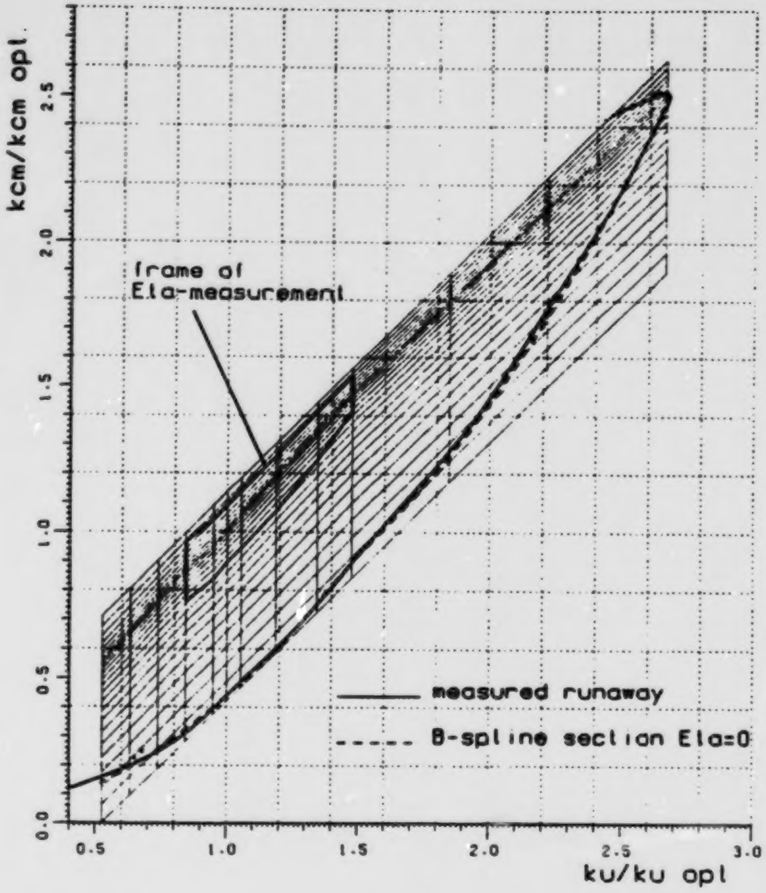

Fig. 2 Grid for approximating the η-surface of a propeller turbine

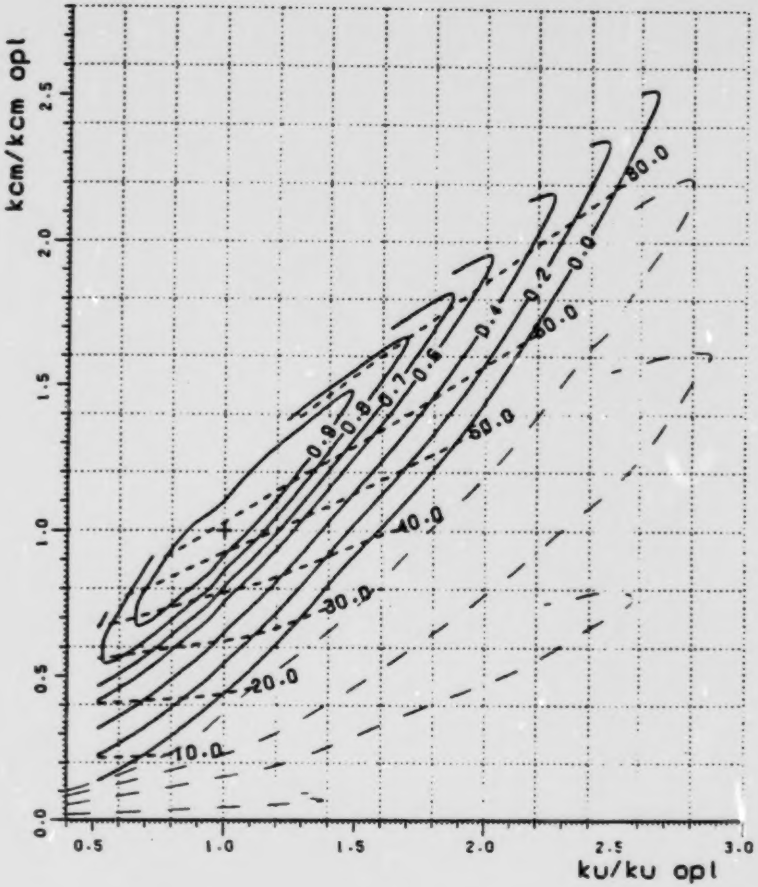

Fig. 3 B-spline hill chart of a propeller turbine
—— η/ηopt. = const., – – – Φ = const.,
–·– runaway curves for several β2 = const.

This very same method using B-spline approximation is also successfully applied for CNC machining purposes to numerically model any shape of turbine runner blades and Pelton buckets, as well as auxiliary surfaces like blade welding edges, inlet and outlet, edges, fillet radii, etc.

4. Numerical modelling of turbine characteristics

The model test measurements and the numerical modelling of their results (approximation) is the most extensive for a double regulated Kaplan type turbine. The model testing consists usually of measuring efficiency η versus dimensionless head (kul) and dimensionless discharge (kcml) for different wicket gate openings Φ. This series of measurements is then repeated for different runner blade openings $\beta 2$. The approximation process is done in different steps:

1. Transfer of measured model test data (collected by fully automatic data acquisition programs) from the lab-computer to the main frame computer.

2. Linear splines trough

   $\eta = f\ (\text{kcml})$ for $\text{kul}(i) = \text{const.}, \quad i \in (1,n)$

   to check consistency of measurements and to interpolate additional "results" between measured operation points and measured runaway points.

3. Parameterization: definition of grid points (vertices) for the complete operation range (Fig. 2)

4. Linear least squares: calculation of B-Spline coefficients for the surfaces:

   $$\left.\begin{array}{l}\eta = f\ (\text{kul},\ \text{kcml})\\ \Phi = f\ (\text{kul},\ \text{kcml})\end{array}\right\}\ \begin{array}{l}\text{for } \beta 2(i) = \text{const.}\\ i \in (1,n)\end{array}$$

5. Plot of propeller hill charts showing lines of constant efficiency and wicket gate opening (fig. 3); each hill chart is for a constant $\beta 2$.

.../8

6. Calculation of Kaplan curve: enveloping efficiency curve η = f (kcml) over different runner blade openings $\beta 2$ for a constant head kul (fig. 4).

7. Approximation of envelop surface η = f (kul, kcml) based on the Kaplan curves.

8. Plot of Kaplan (double regulated) hill chart showing lines of constant efficiency, wicket gate and runner blade openings (fig. 5).

This procedure is also applied to generate other turbine characteristics, such as cavitation coefficients.

5. Turbine selection based on B-spline characteristics

The parameters involved in the optimization of a turbine selection for a hydro plant are many. For this reason the tendency is to group the parameters into various categories.

One category can group the model parameters, those parameters related to the efficiency surface of the turbine itself. This involves the type of selected model (Francis, Kaplan etc.) and the type of regulation such as double regulated, etc. These parameters are not dependent on the choice of runner diameter or speed and therefore called model parameters.

During the feasibility stage of a project some of the model parameters are identified and stated as established or given parameters during the final optimization work of a bid.

So-called plant parameters include runner diameter, number of units, setting level and turbine speed. These parameters can be varied independently of the model parameters during the selection optimization work. Other plant parameters include maximum installed capacity of output and maximum discharge.

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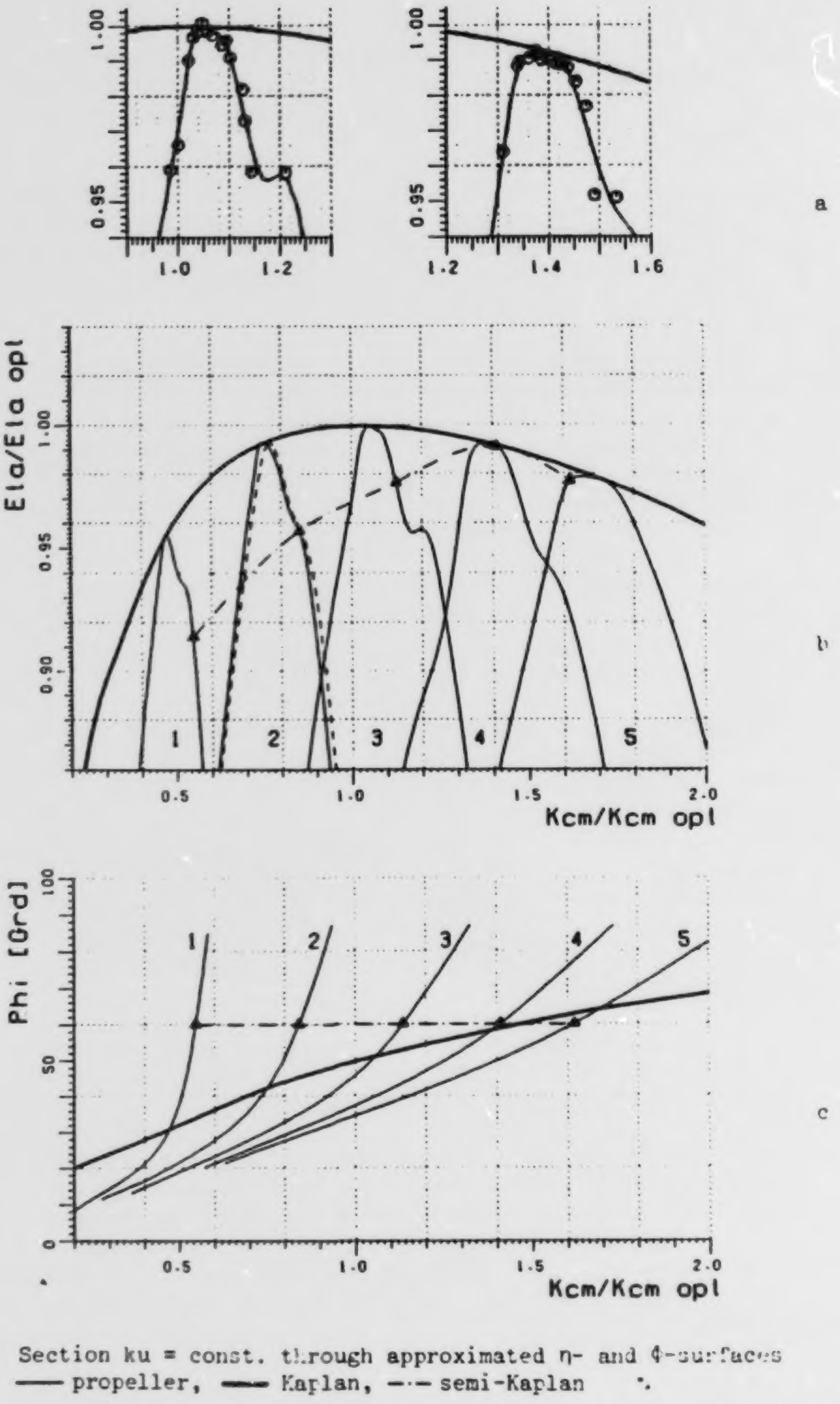

Fig. 4 Section ku = const. through approximated η- and Φ-surfaces
—— propeller, ▬▬ Kaplan, —·— semi-Kaplan

a) Comparison with measured points (close-up of propellers 3, 4)
b) -- interpolated propeller close to measured propeller
c) sections through Φ-surfaces

Due to the number of parameters to be manipulated it becomes evident that without special working tools a timely solution to the optimization of the major variables of a hydro plant becomes very difficult.

In order to facilitate the task of performing turbine selection or optimization computations, Sulzer-Escher Wyss has applied the B-spline program system to the modelling of the turbine characteristics which are included within the so-called model parameters.

In so doing a complete and uniform computer simulation of turbine characteristics in the form of a data bank is available for any model. This model data bank would include independent files for each performance characteristic, such as efficiency, cavitation number, runaway speed and for double regulated units independent surfaces for wicket gate openings and runner blade openings.

Each independent variable mentioned would typically be given as function of the unit speed/head Kul and unit flow Kcml. In fig. 7 an example is shown with cavitation number as function of a given range of Kul and Kcml.

Limitations of each model are incorporated in the B-spline surfaces. These limits on model performance include maximum runner blade openings, part load limitations as well as maximum output due to power saturation.

Typically a specification may limit maximum available flow and maximum installed plant output further reducing the number of parameters to be manipulated during optimization computations. These restrictions being part of license or environmental considerations.

With this understanding of the number and nature of parameters to be manipulated the power and flexibility of the B-spline program system can be put to work.

The usual approach is to use the B-spline approximations of of the chosen model and use the B-spline system programs to calculate annual energy production while accessing the hydraulic characteristics of the river and data bank with turbine performance. The hydraulic characteristics of the river would include flow duration data as well as headwater and tailwater data.

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In order to limit computation time and complexity it is usual to identify variables as dependent and control variables.

In a typical example where the turbine type, type of regulation and maximum plant output and flow is identified and stated as so-called given parameters then a breakdown of dependent and control variables could be as given:

dependent:	turbine speed
control:	runner diameter turbine setting elevation

The power of B-spline lets the user define the speed range and the program system will perform the iterations to calculate the best speed, that is the speed maximizing annual energy production, for the given control variables of runner diameter and setting.

Due to the speed of the B-spline system it is relatively easy to generate a matrix, at a given turbine setting, for turbine diameter, turbine speed and corresponding annual energy production. The B-spline approximation of the matrix is plotted as in fig. 1 with annual energy production plotted as function of speed and diameter. The peak of the surface leads to the turbine diameter and speed maximizing annual energy production.

Other graphical representations of the relationships between annual energy production and dependent and control variables are plotted to allow the user to identify the combination of variables which will lead to the best solution for a project.

For example, annual energy production plotted as function of turbine setting for a given diameter will allow the user to identify the rate at which the production level increases as the setting is lowered. Also available from the graph will be the setting at which the annual energy production increases no longer due to other limitations such as power saturation of the model.

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Net present value calculations are performed to identify the final selection. For various turbine settings the optimum turbine diameter and speed are found using B-spline. For lower settings the turbine diameters are smaller and rotational speeds are higher leading to lower equipment costs.

The relationship between civil works costs and generating equipment costs as well as predicted revenues is evaluated using present value analysis to determine the final selection.

6. Description of Port Dalhousie project

The project is located in St Catharines, Ontario, Canada on the south shore of Lake Ontario.

The two hydroelectric turbines located on the site will exploit the head available between the Martindale Pond and the Dalhousie Harbour. The flow conditions for the Port Dalhousie project will usually be uniform due to the regulation from the flow through the De Cew Falls generating station which is upstream of the Dalhousie site.

Hydraulic conditions

Martindale Pond (headwater) Normal elevation	78.67 meters
Port Dalhousie Harbour (tailwater) Normal elevation	74.78 meters
Normal Gross Head	3.89 meters
Full Load Net Head	3.70 meters
Normal Annual Range of Full Load Net Head	3.5 to 4.0 meters
Range of Available Flow	125 to 245 cms

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Design Net Head	4.0 meters
Design Maximum Flow	100 cms/unit
Number of Machines	two

As mentioned the available flow is unusually uniform with a flow rate of 180 cms exceeded 82% of the year. The flow duration curve is very flat between the 20% and the 82% exceedance marks. The flow characteristics of the project lend themselves well to the application of so called Propeller or fix runner blade turbines.

7. Application of B-spline system for performing turbine selection computations for the Port Dalhousie Project

As mentioned in the previous section the flow conditions of the project allows for the application of single regulated turbines. In this case the wicket gates of the horizontal pit turbine are adjustable (regulated) and the runner blades have a fixed position. This being the so-called propeller arrangement.

The specification of the project also called for a double regulated horizontal unit as an alternative. In both cases the B-spline program system was used to perform the required computations to determine the final turbine selections.

As described in section 4 the B-spline approximation of a double regulated hill chart is obtained by approximating the envelops of the measured propeller surfaces. See section 4 for details. It follows that as a result of the model testing procedure there are propeller hill surfaces, for the various measured constant runner blade openings directly available.

Due to the use of the B-spline program system it is possible to generate propeller hill surfaces for intermediate runner blade openings between the measured openings used during model testing. This feature of the B-spline system was required for the Port Dalhousie turbine selection work in order to generate the various propeller surfaces required to perform the annual energy production calculations, as described in section 5, and to check other requirements of the propeller solution of the base bid of the project.

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In order to create the intermediate propeller surfaces the BS system programs perform two operations. For a chosen intermediate propeller surface the program interpolates between two measured surfaces by considering the tangential condition to the Kaplan envelop of the surfaces. The shape of the intermediate surface is obtained by using the average of normalized sections of the two existing measured surfaces.

The accuracy of the BS system for such operations as performed for the Port Dalhousie project is shown in fig 4b. The dotted line being an interpolated propeller curve obtained by applying the above mentioned system between the curves numbered 1 and 3. This procedure was performed without taking the surface numbered 2 into account. It can be seen that both efficiency level and shape are very close to the measured surface numbered 2.

For the Port Dalhousie project flow duration data was given as well as information regarding headwater and tailwater as mentioned in section 6.. Also given in the tender were specific prototype performance requirements including:

- Each unit (generating set) having a nominal rated capacity of 3375 [KW] under the design net head of 4.0 [m] and maximum design flow of 100 [cms]

- Maximum efficiency of each machine to occur at normal net head of 3.7 [m] and turbine flow 95 cms. This requirement applying for the propeller alternative.

As given above certain so-called plant parameters (see section 5.) were given for the Port Dalhousie project. Model parameters (see section 5.) were also given in the tender by specifying the use of horizontal pit turbines as well as the type of regulation. Propeller for base bid and double regulated as alternative.

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Given the above input the B-spline program system was used to optimize the turbine selections and determine the following parameters:

- turbine diameter
- turbine speed
- turbine setting elevation
- for propeller alternative the runner blade opening

For the Port Dalhousie project the turbine setting elevation was defined by the minimum coverage of the bell mouth intake and draft tube ceiling. Unlike the discussion given in section 5. regarding turbine setting considerations, for the Port Dalhousie project the setting was a direct function of turbine diameter due to the minimum coverage considerations and not on cavitation limitations as is usually the case for higher head sites.

The above consideration eliminates one independent parameter and limits the optimization to turbine diameter, speed and runner blade position for the propeller solution.

As mentioned in section 5. the usual practice is to identify control and dependent variables. For the Port Dalhousie project the annual energy production as well as the location of the peak efficiency and full load design operation points must be considered during the optimization work. For this reason the parameters are categorized as follows:

dependent parameter: turbine speed

control parameter: turbine diameter
runner blade position

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Unlike the general discussion given in section 5, here the second control parameter is the fix runner blade position of the propeller solution. The iterative process begins by selecting a fix runner blade position. For convenience one of the constant runner blade angles measured during model testing is chosen. The propeller hill diagram corresponding to the chosen runner blade position is retrieved from the data bank and the B-spline approximation is displayed. Based on the requirements for the two given operation points for maximum efficiency and full load design output a turbine diameter and speed is calculated and displayed on the propeller hill diagram. The hill diagram would essentially appear as shown on fig. 3.

The optimization process is continued by defining maximum and minimum turbine speeds and the efficiency scale up factor to be applied to the model hill diagram in order to obtain the prototype performance for the preliminary runner blade angle. Following these inputs to the B-spline program system the annual energy production is evaluated for the speed range and best turbine speed is found for the given prototype runner diameter and runner blade position. The user can display the location of the two given operation points and if satisfied the results are stored in memory and used for comparison with further results.

If the runner blade angle which is initially chosen does not lead to satisfactory performance levels for the given operation points and maximized energy production then a new runner blade angle is specified. This blade angle is likely to be an intermediate value between two previously measured runner blade positions during model testing. As described earlier the B-spline program system would be used to obtain the B-spline approximation of the surface. With this new surface approximation displayed the previously calculated or a new choice of diameter and speed can be used to show the location of the given operation points. The iterative process is continued to maximize average annual energy production for the most competitive selection of turbine diameter and speed while meeting the two operation point requirements for full load design output and maximum efficiency.

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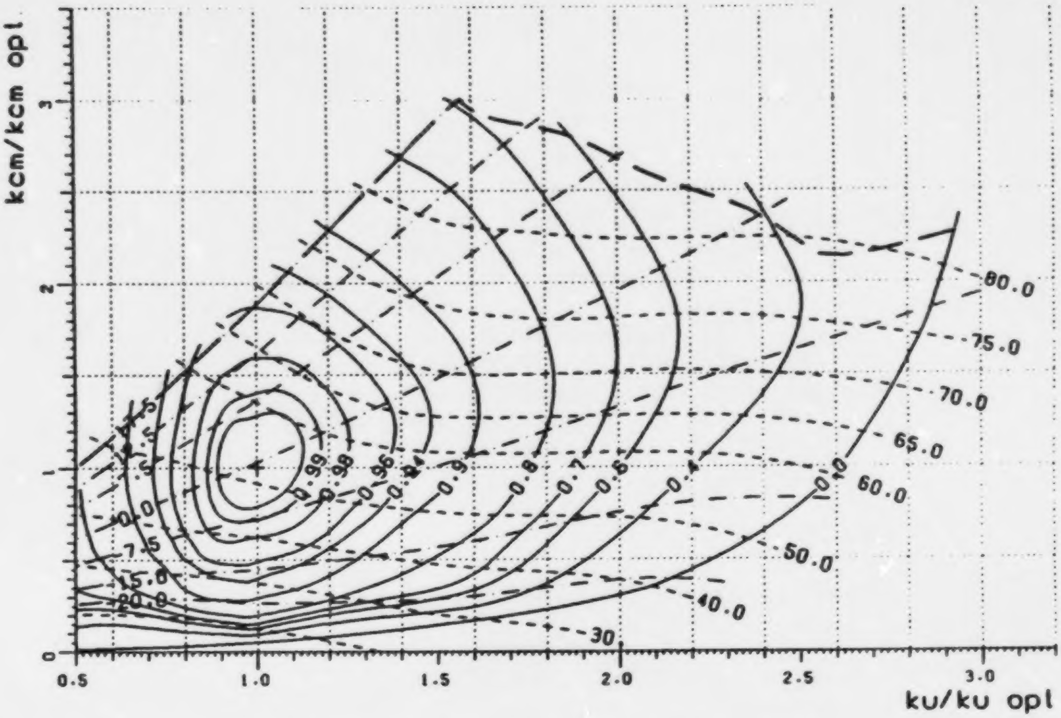

Fig. 5 B-spline hill chart of a double-regulated turbine
—— η/η_{opt} = const, — — P saturation, - - - Φ = const., -·- $\beta 2$ = const.

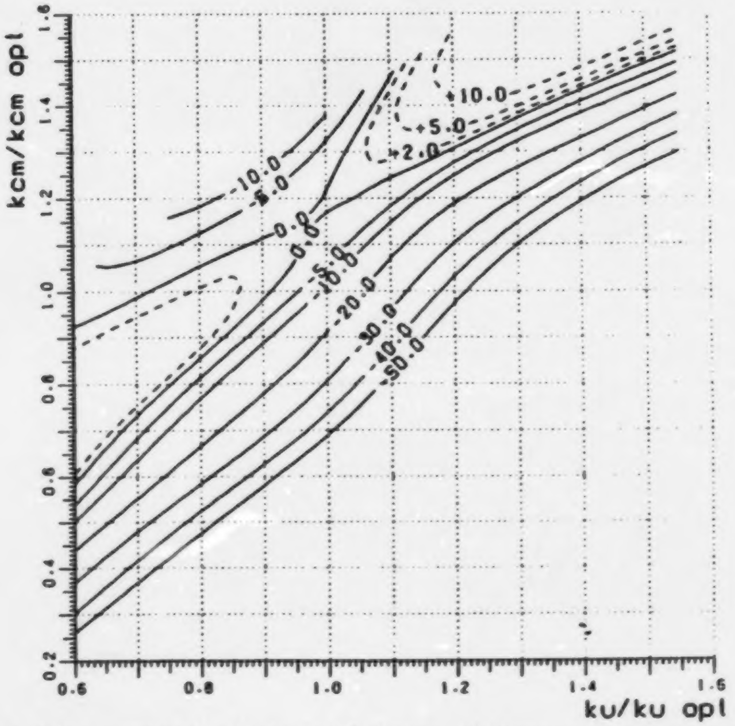

Fig. 6 B-spline surface of the efficiency difference between propeller and semi-Kaplan-turbine ($\eta_{Prop} - \eta_{S.K.}$)

For final verification of the chosen turbine selection the B-spline program system is utilized to manipulate the prototype propeller surface approximation. The guarantee points are plotted on constant Kul cuts taken from the B-spline approximation of the final propeller hill diagram. For these Kul cuts the unit efficiency or specific output is plotted against specific flow and on the corresponding display considerations such as reserve from power saturation points are verified. Another example is shown on fig. 8 where unit power is plotted as function of the speed number Kul for various constant wicket gate openings.

Double regulated solution

For the double regulated solution of the alternative bid the turbine diameter is specified by the results of the base bid propeller unit. The optimization is again handled by the B-spline program system and the remaining parameter to be calculated is turbine speed. In this case the optimization is straight forward since based on speed range and previously established turbine setting elevation and diameter the B-spline program system determines the turbine speed which maximizes average annual energy production.

Corresponding to the chosen turbine speed, given diameter and efficiency step up the prototype double regulated hill chart B-spline approximation is displayed. On the display the full load design output operation point is shown and if desired the various operation points from the annual energy calculation. From this display the maximum runner blade opening as well as wicket gate opening are noted.

Due to the very flat flow duration curve and small head variations as described in section 6. the superior energy production level of the double regulated alternative was marginal as compared to the results of the base bid propeller alternative. Given the lower unit costs of the propeller turbines in the case of the Port Dalhousie project the cost of a kilowatt-hour was lower for the horizontal propeller pit turbine and consequently chosen during the bid evaluation.

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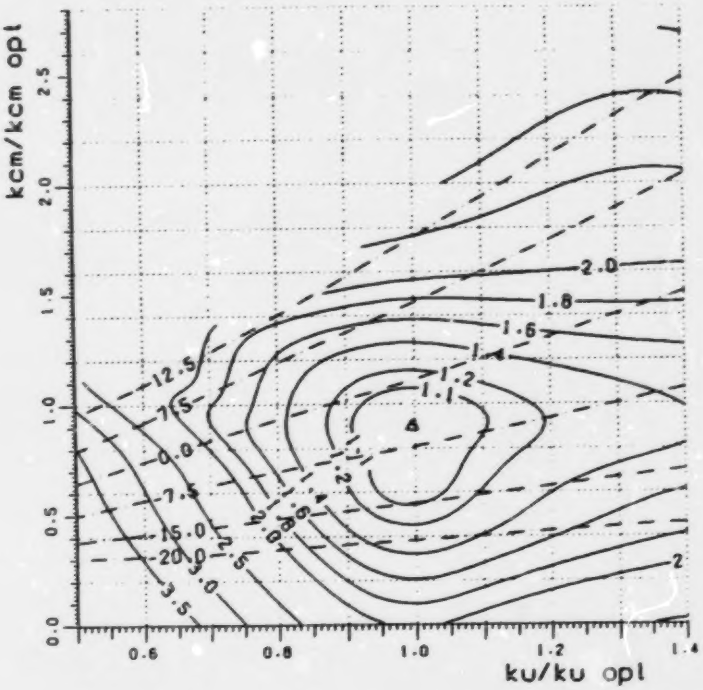

Fig. 7 B-spline surface of admissible sigma-values (σ/σ_{min})

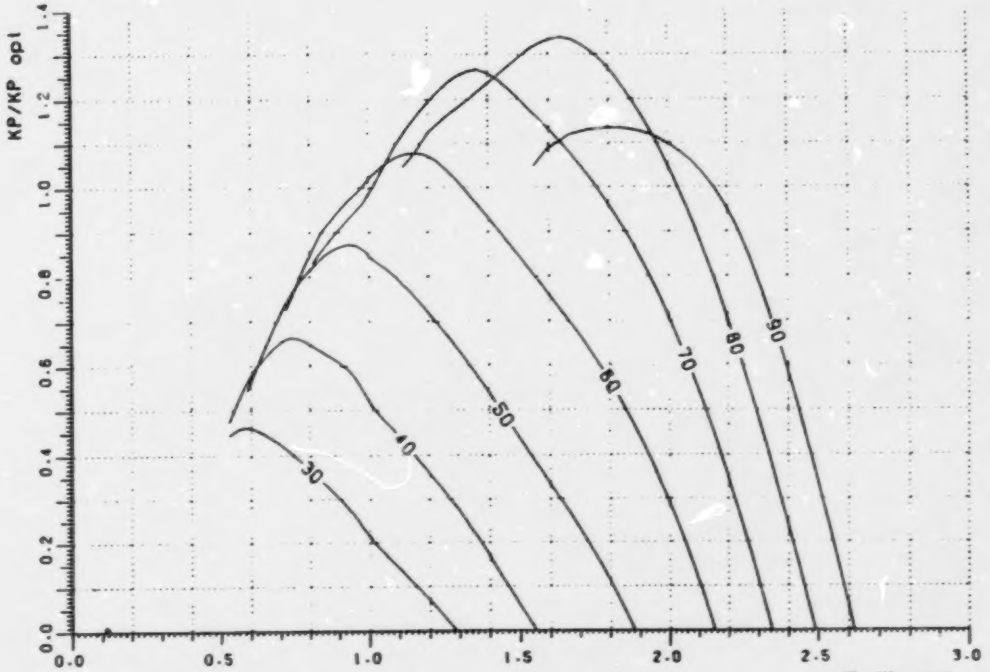

Fig. 8 Set of KP-characteristics generated from the B-spline surface of a propeller turbine (numbers correspond to the gate opening which is kept constant for unregulated turbines)

Conclusions

The B-spline modeling technique fulfils the requirements to obtain precise mathematical representations of measured turbine characteristics due to its properties such as smoothnes, accuracy and flexibility.

The approximation process has been standardized by means of command procedures linking different programs of the B-spline program system thus enabling quicker availability of new model test results.

The integration of the B-spline program system at DBS Escher Wyss has allowed for timely optimization of the parameters involved in turbine selection work.

Manipulation of B-spline computer approximations of turbine hill surfaces allows for representations of pertinent turbine performance characteristics.

Acknowledgement

The authors wish to thank their colleagues H. Keck, H. Bantli and Ch. Schaerer from Sulzer-Escher Wyss who have developed and made available the diagrams used in this paper.

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Nomenclature

D	runner diameter
H	net head
$kcm = cm \cdot (2gH)^{-1/2}$	discharge number
$cm = Q \cdot (D^2 \cdot \pi / 4)^{-1}$	average meridional flow velocity
$ku = u(2gH)^{-1/2}$	speed number
$u = \omega D/2$	circumferential speed
$KP = \eta \cdot kcm$	output number
n	rotational speed (rpm)
P	turbine output
Q	discharge
$\beta 2$	runner blade opening
η	efficiency
σ	cavitation coefficient
Φ	wicket gate opening

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Dynamic Simulation of Regulated Water Turbines

By
J.E. Stewart, J.U. Thoma

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Dynamic Simulation of Regulated Water Turbines

James E. Stewart and Jean U. Thoma

Abstract

A water turbine with electric generator, hydraulic head variations and control of inlet guide vanes is a complex system, especially if electric load rejection and start up is included. Standard control engineering methods can be usefully supplemented by a bondgraph. A bondgraph of a system leads to simulation on a PC using the TUTSIM program.

In a fundamental bondgraph approach, the main turbine relations are taken from Eulers turbine equation and conservation of power. Various parasites such as turbine inefficiency, bearing and generator losses, moments of inertia, and water momentum determine efficiency and dynamic performance. Parameter values come from physical principles and are supplemented by matching the simulation results to measured performance curves. An alternative approach is to replace the turbine bondgraph elements with a custom TUTSIM user block written in the `C' programming language.

The finished model allows the systems engineer to simulate various operating conditions, stability and transients in the electrical, mechanical, fluid and control subsystems.

Bondgraphs[1,2]

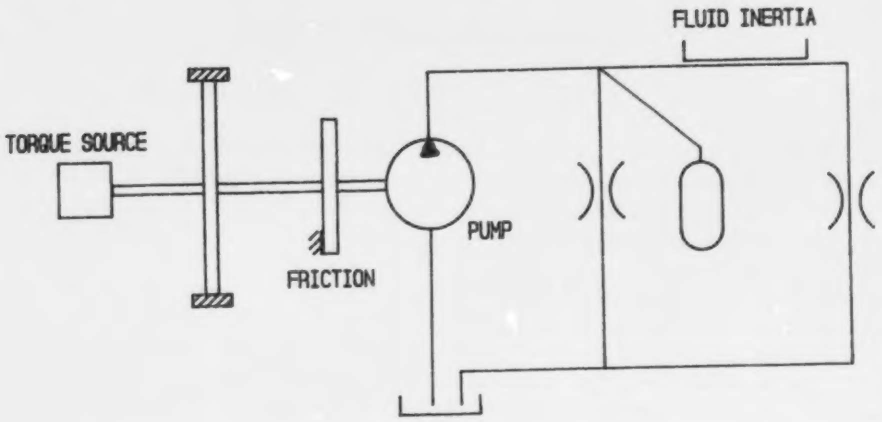
A bondgraph is a simple and rigorous method of system representation, developed by Henry Paynter in 1923.

The principle of bondgraphing is based on multidisciplinary analogies of common system elements. For example, linear speed, angular velocity, volume flow, electrical current, and magnetic flux are inherently related in the sense that they are all rate of change of some positional characteristic. Other similar multidisciplinary generalizations can be made, some of which are listied in Appendix A along with the generic bondgraph nomenclature.

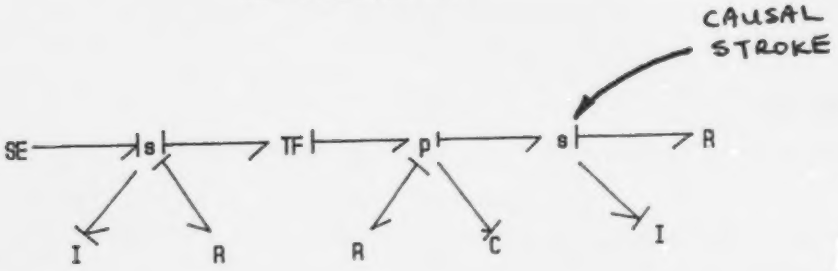
A system is represented by resistors, inertias, capacitances, and other bondgraph elements interconnected by bonds. Bonds lie along the power transmission path between two elements or nodes, and simultaneously represents the flow and effort variables that act along this path. For example, in a rotational mechanical system, a shaft which transmits torque and has a rotational speed and therefore transmits power, is represented by a bond which transmits an effort (torque) and has an associated flow (angular velocity).

As one might suspect, the same bondgraph can represent two or more systems which although they come from different disciplines, possess the same dynamic characteristics. A sample of this is given in Figure 1 which shows the bondgraph for a simple hydrostatic system and its electrical analog. This bondgraph shows why bondgraphs are often described as a piece of paper that a chicken with dirty feet has run across.

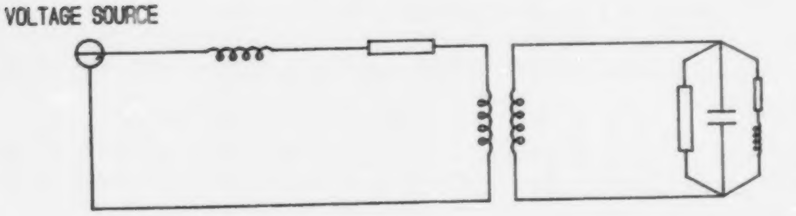
Once a bondgraph has been drawn, it is completed by the `assigning of causalities', another bondgraph term which describes the assignment of cause and effect sense of the dynamic model variables. Knowing that a simple block diagram can be inverted between derivative and integral forms implies a choice for the analyst. Knowing that a computer performs integration much easier than differentiation decidedly places the preference on the integral form of block diagram. Following some simple rules it is possible to place causal strokes at one end or the other of each bond to keep track of the causal assignment (see Figure 1).


FLUID INERTIA
TORQUE SOURCE
PUMP
FRICTION

HYDROSTATIC PUMP UNIT


CAUSAL STROKE
SE
s
TF
p
s
R
I
R
R
C
I

BONDGRAPH


VOLTAGE SOURCE

EQUIVALENT ELECTRIC CIRCUIT

Figure 1: Multidisciplinary System Representation

Even when it seems impossible to maintain integral causality through out the model, the bondgrapher usually has some tricks which will solve most of these problems. Although a bondgrapher very seldom needs to generate a block diagram the importance of keeping the integral forms of the equations for computation is understood and is easily invoked by the assignment of causal strokes.

Once the causal strokes of the bondgraph have been assigned, the model is complete. The analyst must now determine the appropriate parameter values for the elements before simulation can begin. To illustrate the advantage of the bondgraph-TUTSIM simulation scheme, the selection of parameters (which must be performed under any simulation scheme) consumes roughly 90% of the required preparation time.

A summary of the common bondgraph elements is included as Appendix B.

TUTSIM[3]

TUTSIM is a commercial computer program for the simulation of continuous dynamic systems on a PC. TUTSIM originated at the Twente University of Technology, The Netherlands (hence TUT-SIM). The program is available in North America from Applied i^3. The program is simple to use (about as difficult as learning a spreadsheet program) and requires that the user be familiar with PC's but need not necessarily be a professional programmer.

Users must necessarily be competent in their field, but are removed from handling computer algorithms, since TUTSIM blocks which represent mathematical equations handle these operations in the background of the program. Model parameters are easily entered and changed. Output of the program can be any block output variable. Results can be displayed either numerically or graphically on the computer screen, printer, or disk (ASCII format) disk file. The disk file format is attractive since the graphical display is somewhat rudimentary and the analyst might prefer to generate final graphs using some other graphics package.

Combining TUTSIM with bondgraphing gives a simple and rigorous method for dynamic simulation.

Hydraulic Turbine Simulation

The dynamic response of a turbine can be approximated by the steady state performance as indicated by it's performance characteristic[4]. The performance of a singly regulated turbine (eg Francis or propellor turbine) can be uniquely determined as the function of unit speed and inlet guide vane angle For Kaplan turbines, an additional independent variable describing the turbine blade angle must be added. The dependent variables are usually taken as unit power and unit flow (or alternatively unit power and efficiency). Unfortunatly this choice of dependent variables has the drawback that at zero unit speed the unit power must be zero by definition (since power is the product of torque times speed) and so no information is available for the torque at zero unit speed. Since the startup performance of a turbine is strongly dependent on the torque at zero unit speed (ie the blocked rotor torque) the analyst should prefer to work with turbine performance in terms of unit torque and unit flow as a function of unit speed and inlet guide vane angle.

If the analyst is provided with unit power information it may be converted using the formula below and extrapolated to zero unit speed;

$$T_{11} = T/(D^3 H) = 30 P_{11}/(N_{11} \pi)$$

T11 = metric unit torque [kN m]
T = torque [kN m]
D = throat diameter [m]
H = net head [m]
P11 = metric unit power [kW]
N11 = unit speed [RPM]

An elegant but not very successfull approach to turbine simulation is to try to model the turbine using standard bondgraph elements using Euler's equation for turbines and conservation of power as a starting point.

Euler's Equation;

$$p = \rho (u_1 w_1 - u_2 w_2)$$

p = net pressure on turbine [Pa]
ρ = density of water [kg/m^3]
u = periferal runner velocity [m/s]
w = tangential component of the water velocity [m/s]
$_1$ = subscript for turbine inlet
$_2$ = subscript for turbine discharge

Based on the fact that a good turbine design, operating at its design point, will have very little tangential velocity component (swirl) in the water at its discharge,. the following idealization is made;

$$u_1 w_1 >> u_2 w_2$$

so roughly speaking;

$$p = \rho u_1 w_1$$

continuing;

$$u1 = \omega r_1$$

$$w_1 = v_1 \cos(\alpha)$$

$$Q = V = 2 \pi r_1 h v_1 \sin(\alpha)$$

where;

r_1 = radius of the turbine at its inlet edge [m]
α = angle between w_1 and v_1
h = the height of the turbine inlet [m]
ω = angular velocity of the turbine

now;

$$v_1 = V/(2\pi r_1 h \sin(\alpha))$$

$$w1 = V/(2\pi r1 h \tan(\alpha)$$

$$p = \rho \omega r_1 \dot{V}/(2\pi r_1 h \tan(\alpha))$$

giving;

$$p = k \omega \dot{V} \qquad \text{(i)}$$

where;

$$k = \rho/(2\pi h \tan(\alpha))$$

From the power conservation relationship assuming 100% efficiency (note that all inefficiencies are evaluated using resistors in a bondgraph);

$$p \dot{V} = T \omega$$

using (i);

$$k \dot{V}^2 = T \qquad \text{(ii)}$$

Equations (i) and (ii) can be modelled using the bondgraph shown in Figure 2. Three resistors have been included to account for any inefficiencies. The drag resistor (R_d) on the hydraulic side of the turbine is used to account for losses associated with the water flow as it passes through the turbine in series with the main water flow (mainly Prandtl type boundary layer losses and kinteic energy losses out the draft tube). The slip resistor (R_s) is used to model losses which occur parallel to the main water flow (for example leakage around the band of a Francis turbine). The third resistor (R_b) is used to model the bearing losses that occur on the shaft end of the turbine .

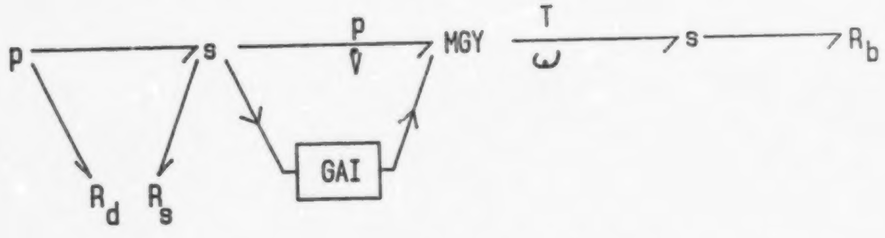


Figure 2: Hydraulic Turbine Bondgraph

As one might expect, the parametric values of R_d and R_s must be a function of the operating condtions of the turbine, that is will be a function of unit speed and inlet guide vane angle due to the large non-linearities of the flow. Although TUTSIM allows modulation of the resistor parameters as a function of any other single parameter using the TUTSIM `FNC' block, modulation based on two parameters is not easily performed. In addition selecting just how these parameters should vary is a very tedious trial and error task.

As a matter of proceedure a bondgraph of a full turbine is shown in Figure 3. The TUTSIM code is included as Appendix C. This model is assumed to operate at a single inlet guide vane setting to simplify matters somewhat. The simulation starts with the turbine stopped and the inlet guide vanes at the design value. The turbine accelerates until the synchronous speed is reached and the generator is switched on. After 5 seconds, the generator is switched off to demonstrate runaway performance.The results of the simulation are shown in Figure 4. Upon a quick inspection, the torque never drops off to zero so the turbine continues to accelerate during runaway. A closer examination of the turbine data showed that there was only rough agreement between the bondgraph turbine model and the actual turbine characteristic.

Herein lies the difficulty of a strict bondgraph-TUTSIM turbine model. Multiple simultaneous non-linear losses are not easily handled. It is important to note that it is these very losses which makes the strict analytical design of turbine runners a thing of the future. Fortunatly, there is a solution to this problem provided by the TUTSIM program for the dynamic analyst.

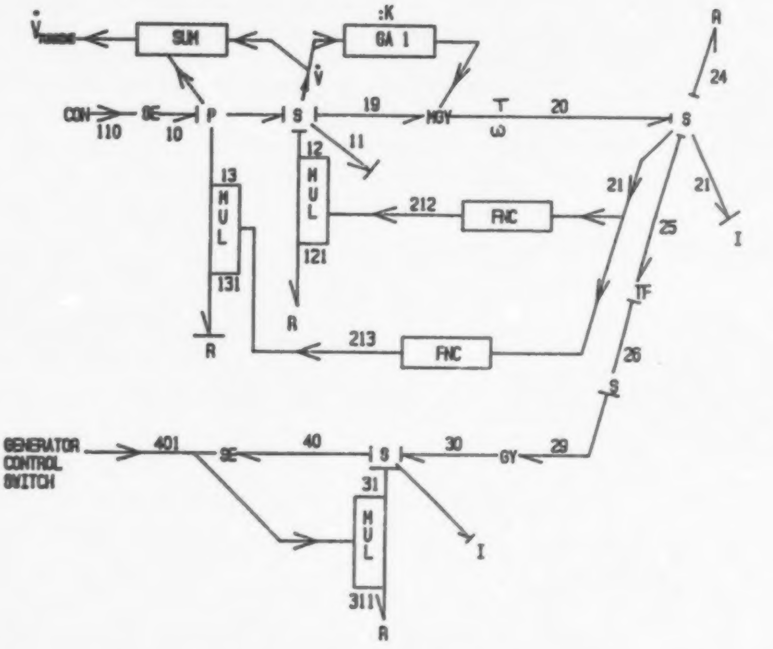
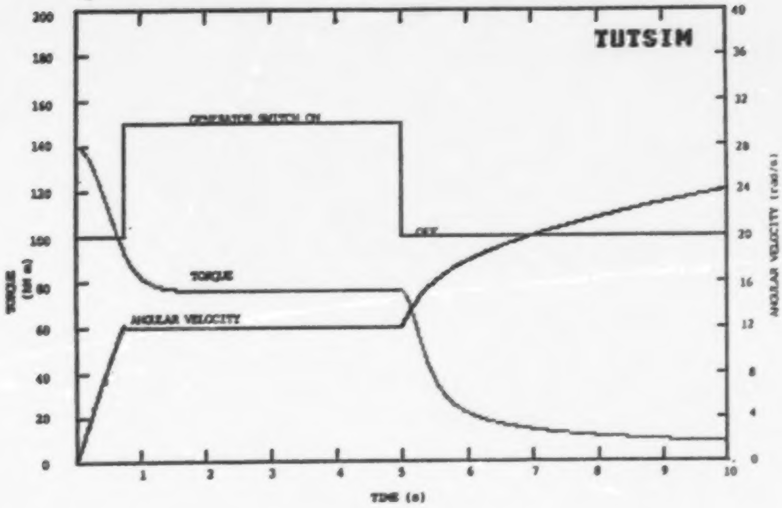


FIGURE 3: BONDGRAPH OF HYDRAULIC TURBINE

Figure 4

Dynamic Simulation Using the Bondgraph Turbine Model



Making Use of the TUTSIM User Defined Block

Upon realizing that the analyst has the necessary performance information at hand in the form of the turbine performance characteristic, there is the alternative of writing a custom TUTSIM block. The TUTSIM program allows users to write there own subroutine in either `C' or FORTRAN and incorpoate it into simulations.

In terms of turbine simulation, a routine which calculates torque and flow as a function of unit speed and inlet guide vane angle can now be produced based on the performance chart of a given turbine and incorporated into the simulation model. There is no need for estimating resistance parameters, so the turbine data is in full agreement with the steady state performance data. A listing of a sample turbine usercode written in `C' is included as Appendix D. A block-bondgraph which uses this code is shown in Figure 5. The results of the simulation are shown in Figure 6. The TUTSIM code is located in Appendix E.

The turbine now performs as expected and can now be incorporated into more complex and usefull applications.

Some possible areas of interest to the analyst that can be handled with the bondgraph-TUTSIM approach include;

1. Dynamics of output changes and interaction with either a mechanical govenor or programable logic controller.

2. Fluid transients in the water supply conduit due to load rejection or load changes including interaction with bypass valves, accumulators, and surge tanks etc.

3. Start up and synchronization behavior and control.

4. The design of mechanical, electrical, and control equipment based on the above considerations.

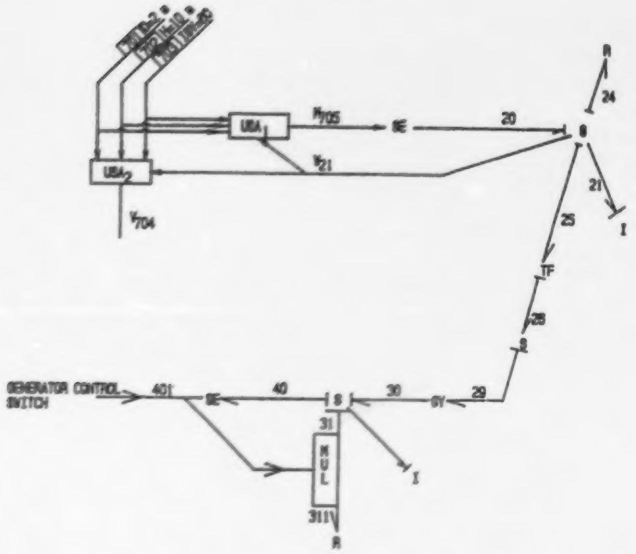
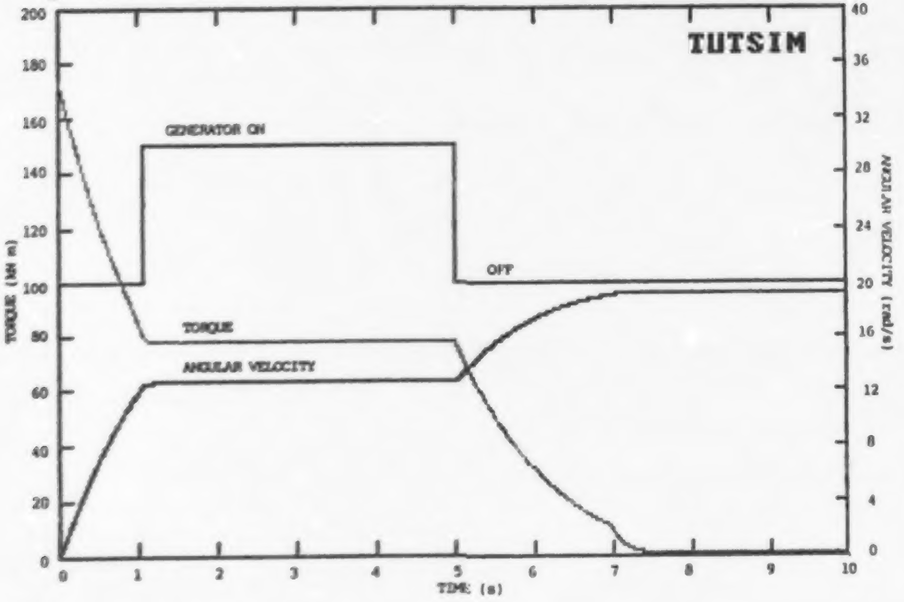

UBA1
UBA2
W705
SE
20
0
24
R
W21
21
I
V704
25
TF
28
0
29
GY
30
1
40
SE
401
GENERATOR CONTROL SWITCH
31
MUL
311
R
I

FIGURE 5: BONDGRAPH OF HYDRAULIC TURBINE WITH USER BLOCKS

Figure 6

Dynamic Simulation Using the User Defined Block Turbine Model



References

1. Jean Thoma; Introduction to Bondgraphs and Their Application; Pergamon Press, Oxford, U.K., 1974

2. R.C. Rosenburg, D.C. Karnopp; Introduction to Physical System Dynamics; McGraw Hill, 1983

3. Applied i; TUTSIM Users Manual, V6.00; Applied i, 200 California Ave, Suite 212, Palo Alto CA, 94306, (415) 325 4800

4. Wylie and Streeter; Fluid Transients; McGraw Hill, 1978, p103

Author's Background

Jim Stewart is a graduate of the University of Waterloo. As a mechanical engineer with Turbex International he is involved with the mechanical and fluid design of hydraulic turbines. In addition he is responsible for computer operations at Turbex.

Jean Thoma is a professor at the University of Waterloo. His many books and papers concentrate on the dynamic simulation of fluid power control systems

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Mechanical Engineer

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APPENDIX A

Bondgraph	Fluid Power	Linear Mechanical	Electrical	Rotational Mechanical	Magnetic
effort (e)	pressure	force	voltage	torque	magneto motive force
flow (f)	flow	velocity	current	angular velocity	flux
R	leakage	friction	resistance	friction	reluctance
I	fluid mass	mass	inductance	moment of inertia	
C	fluid compressibility	spring constant	capacitance	torsional spring constant	
impedence TF		lever	tranformer	gearbox	
displacenet (q)	volume	position	charge	angular position	
momentum (p)	fluid momentum	momentum	flux	angular momentum	

Major Bondgraph Equations

$\text{Power} = e*f$

$\text{Energy} = \int(\text{power})dt$

$q = \int(f)dt$

$p = \int(e)dt$

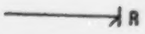
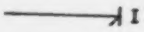
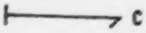
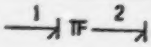
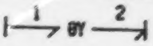
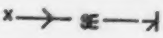
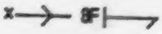
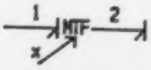
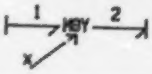
$e = q/C$

$f = p/I$

$e = f/R$

All elements are energy conserving except for the R element. All losses are accounted for through the use of R elements connected either in parallel (slippage losses) or in series (drag losses).

Appendix B

	Resistor	$f = e/R$
	Inertial Element	$f = 1/I*\int(e)dt$
	Capacitor	$e = 1/C*\int(f)dt$
	Transformer	$e_2 = k*e_1 \quad f_1 = k*f_2$
	Gyrator	$e_2 = k*f_1 \quad e_1 = k*f_2$
	Effort Source	$e = k*x$
	Flow Source	$f = k*x$
	Modulated Transformer	$e_2 = x*e_1 \quad f_1 = x*f_2$
	Modulated Gyrator	$e_2 = x*f_1 \quad e_1 = x*f_2$

Appendix C: TUTSIM Code for the Bondgraph Turbine Model Simulation

```
PROFESSIONAL VERSION OF TUTSIM

Model File: turb75.sim
Date:      7 /     6 /  1988
Time:     12 :    30
Timing:    0.0050000  ,DELTA  ;  10.0000     ,RANGE
PlotBlocks and Scales:
Format:
     BlockNo,  Plot-MINimum,  Plot-MAXimum;  Comment
Horz:      0 ,   0.0000     ,  10.0000     ; Time
  Y1:     20 ,   0.0000     , 200.0000     ;
  Y2:     21 ,   0.0000     ,  40.0000     ;
  Y3:    401 ,  -2.0000     ,   2.0000     ;
  Y4:        ,              ,              ;


  98.1000           10 SE      110
   2.3600           11 I        10    -12     -19
  15.4000
                    12 MUL     212    121
                    19 MGY     111     21
                    20 MGY     111     11
   7.4000           21 I        20    -24     -29
   0.0000
   0.0380000        24 R        21
  50.0000           29 GY       31
  50.0000           30 GY       21
                    31 MUL     311    401
 600.0000           40 SE      401
   1.0000          110 CON
   0.5890000       111 GAI      11
   1.0000          121 R        11
                   212 FNC      21
    1    0.0000          6.3000
    2   12.0000          1.5000
    3   20.2000          8.6000
   0.5000000       311 R        30    -40
                   401 MUL     409    507
   0.0000          409 SRS     504    604
                   501 MUL      21    601
                   503 SUM     501    602
   0.0000          504 LOC     503    603
   5.0000          505 PLS
  20.0000
   1.0000
                   507 INV     505
  -1.0000          601 CON
  12.1000          602 CON
   1.0000          603 CON
   0.0000          604 CON
```

Appendix D: `C' Program for the TUTSIM Turbine User Block

```
/* USRCODE.SKE: User Block Skeleton Code to be completed by user. */



/* COMMENT

   COPYRIGHT 1986, 1987 by Applied i, Palo Alto
        All North American Rights Reserved.
   "TUTSIM" is a registered trademark of Applied i
            in USA and Canada.

I/O structure Originated by: Jinner Wolf, 1986.

                        END OF HEADING COMMENT */

#include <stdio.h>
#include <math.h>
extern  float    usr_output[];
float   T11[20][20],Q11[20][20],N11[20],IGV[20];

int     usrcode(iteration,blocknumber,usr_param,input_num,sum_inputs,param1,param2,ind_inputs)

        int   *iteration;    /* number of times USR block has been called */
        int   *blocknumber;  /* blocknumber of this USR block */
        int   *usr_param;    /* /U command-line parameter value */
        int   *input_num;    /* number of individual inputs */
        float *sum_inputs;   /* sum of inputs to this USR block */
        float *param1;       /* first parameter of this usr block */
        float *param2;       /* second parameter of this USR block */
        float ind_inputs[];  /* table of individual input values */




{
int val,indx1,indx2,pntr,rowf,colf,rowt,colt;
char finamet[40],finamef[40];
FILE *muf,*mut;
float   n11,igv,thigh,tlow,qhigh,qlow,t11,q11,d,pi,omega,head;


if(*iteration==1) {                   /* read in data on first iteration from */
                                      /* the files mut.dat and muf.dat */

pi=4.*atan(1.);

strcpy(finamet,"mut.dat");
strcpy(finamef,"muf.dat");

mut=fopen(finamet,"r");
```

```
muf=fopen(finamef,"r");

fscanf(muf,"%d \n",&rowf);
fscanf(muf,"%d \n",&colf);
fscanf(mut,"%d \n",&rowt);
fscanf(mut,"%d \n",&colt);


for (indx1=0;indx1<colt;indx1++)  /* note that N11[0] is a dummy value */



{
fscanf(mut,"%f",&N11[indx1]);
fscanf(muf,"%f",&N11[indx1]);

}
fscanf(muf,"\n");
fscanf(mut,"\n");

for (indx1=1; indx1<rowt; indx1++)
{
fscanf(mut,"%f",&IGV[indx1]);
fscanf(muf,"%f",&IGV[indx1]);

for (indx2=1; indx2<colt; indx2++)
{
fscanf(mut,"%f",&T11[indx1][indx2]);
fscanf(muf,"%f",&Q11[indx1][indx2]);
}
fscanf(mut,"\n");
fscanf(muf,"\n");


}

}
                          /* Bring in the user block inputs */

omega=ind_inputs[1];
head=ind_inputs[2];
igv=ind_inputs[3];
d=ind_inputs[4];

                          /* Calculate the metric unit speed */

n11=omega/2./pi*60*d/pow(head,0.5);

                          /* Find the location in the performance table based on */
                          /* unit speed and the wicket gate angle */

indx1=indx2=1;

do      {
 indx1=indx1++;
          }
          while (n11>N11[indx1]);

do        {
          indx2=indx2++;
          }
          while (igv>IGV[indx2]);

if (*param1==1)                        /* Calculate metric unit torque if parameter1 */
                                       /* is 1 */
{
thigh=T11[indx2][indx1-1]
          +(n11-N11[indx1-1])/(N11[indx1]-N11[indx1-1])
          *(T11[indx2][indx1]-T11[indx2][indx1-1]);

tlow=T11[indx2-1][indx1-1]
          +(n11-N11[indx1-1])/(N11[indx1]-N11[indx1-1])
          *(T11[indx2-1][indx1]-T11[indx2-1][indx1-1]);

t11=tlow+(igv-IGV[indx2-1])/(IGV[indx2]-IGV[indx2-1])*(thigh-tlow);
*usr_output=t11*pow(d,3.)*head;



return(0);

}
if (*param1==2)                        /* Calculate metric unit flow if parameter 1 */
                                       /* is 2 */
{
qhigh=Q11[indx2][indx1-1]+(n11-N11[indx1-1])/(N11[indx1]-N11[indx1-1])
          *(Q11[indx2][indx1]-Q11[indx2][indx1-1]);

qlow=Q11[indx2-1][indx1-1]+(n11-N11[indx1-1])/(N11[indx1]-N11[indx1-1])
          *(Q11[indx2-1][indx1]-Q11[indx2-1][indx1-1]);

q11=qlow+(igv-IGV[indx2-1])/(IGV[indx2]-IGV[indx2-1])*(qhigh-qlow);
*usr_output=q11*pow(d,2.)*pow(head,.5);
return(0);

}
}
```

Appendix E: TUTSIM Code for the User Defined Block Turbine Model Simulation

```
PROFESSIONAL VERSION OF TUTSIM

Model File: turb86.sim
Date:      7 /     6 /  1988
Time:     12 :    51
Timing:   0.0050000  ,DELTA  ;  10.0000      ,RANGE
PlotBlocks and Scales:
Format:
     BlockNo,  Plot-MINimum,   Plot-MAXimum;  Comment
Horz:      0 ,   0.0000     ,  10.0000     ; Time
  Y1:     20 ,   0.0000     , 200.0000     ;
  Y2:     21 ,   0.0000     ,  40.0000     ;
  Y3:    401 ,  -2.0000     ,   2.0000     ;
  Y4:        ,              ,              ;


   1.0000            20 SE      705
  10.6000            21 I        20     -24     -25
   0.0000
   0.0340000         24 R        21
   6.1800            25 TF       29
   6.1800            26 TF       21
   7.9600            29 GY       31
   7.9600            30 GY       26
                     31 MUL     311     401
 600.0000            40 SE      401
   0.1000000        311 R        30     -40
                    401 MUL     409     507
   0.0000           409 SRS     504     604
                    501 MUL      26     601
                    503 SUM     501     602
   0.0000           504 LOC     503     603
   5.0000           505 PLS
  20.0000
   1.0000
                    507 INV     505
  -1.0000           601 CON
  75.4000           602 CON
   1.0000           603 CON
   0.0000           604 CON
   2.0000           701 CON
  10.0000           702 CON
  60.0000           703 CON
   2.0000           704 USA      21     702     703
                                701
   0.0000
   1.0000           705 USA      21     702     703
                                701
   0.0000
```

SESSION 11:

TECHNOLOGY DEVELOPMENT

Chairperson: S. Stevens
Energy Mines and Resources Canada

Combining Hydro Development with Dam Renovation to Cut Costs

By
J.R. Larson

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COMBINING HYDRO DEVELOPMENT WITH DAM RENOVATION TO CUT COSTS

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"Economy is a spur, not an obstacle, to creativity."

So says civil engineer and professor David Billington in his 1983 book, The Tower and the Bridge. In his study of structures from the last two centuries, he finds that the driving force behind some of the best structural engineering achievements was not unlimited funds, but tight budgets. Economy is best achieved through a compromise of minimum materials, efficient construction, and form following function. Billington stresses that the most enduring and aesthetically pleasing projects grew from these principles of economy.

A hydro project in a small community or underdeveloped country provides such a spur to creativity. The meager budgets can be overwhelmed by the vastness of the task. To meet these budgets, we have to resist "doing it the way we did before." This tendency to copy rather than adapt can increase costs.

This paper will describe one project where creative solutions were developed to efficiently and economically transform a low-head hydro dam in a rural town.

THE PROBLEM

With the typical budget restraints, not a single Minnesota city had tried to develop or increase its hydropower in several decades. However, the City of Granite Falls had a problem it could not ignore: an old hydro dam in extreme disrepair.

The 1911 dam is set on the Minnesota River in the heart of the town. Dam failure would threaten over 50 homes and businesses and drain the sole municipal water supply. The dam was an eye-sore, difficult to operate, and costly to maintain. Worse, it met less than half its hydro potential annually, and less than a third during peak conditions.

The municipal dam urgently needed a complete rehabilitation and a substantial increase in hydro capacity. However, with a population of 3,500, Granite Falls had a budget unsuited to large engineering projects.

THE SOLUTION

Granite Falls retained Barr Engineering Co. of Minneapolis to study and resolve the problem. The townspeople were committed to maintaining the dam but, due to a long projected payback period, they were divided on whether to spend money on a hydro addition. Barr Engineering designed an affordable hydro addition based on a creative adaptation of both the project site and a renovation project we had already designed.

The combination renovation/hydro addition was completed in 1987. The historic facility enjoyed a complete renewal and is measurably safer and easier to operate. The Granite Falls Dam is now the focal point of a new municipal park and plaza.

The hydro addition consisted of a new powerhouse, intake structure, and generating equipment with a unit price per KW cost below $1,200. The addition exceeded the proposed capacity by 5 percent, and has shown smooth startup, operation, and shutdown characteristics.

More important, the addition caused a 150 percent jump in hydropower. With an extra 750 KW at a head of 18 feet, the small hydro project now supplies a third of the town's electricity. Granite Falls originally faced a 30-year payback period for the hydro project. Instead, the hydro work is projected to pay for itself in seven years.

THE METHODS

Often, renovation and hydro work are both done at a site, but rarely are they combined. However, Barr Engineering found that combining the two can result in large cost savings. By using this approach at the Granite Falls Dam, we were able to streamline construction and optimize the use of existing structures. The hydro work was a separate contract from the renovation, though, and had to economically viable on its own.

The following describes the hydro addition and how it was economically combined with dam renovation work and the overall facility. Figure 1 shows a plan and cross-section of the hydro addition. Figure 2 provides a "before" and "after" view of the dam. Although the Granite Falls project was dictated by site conditions, dam components, and available equipment, its basic hydro system is adaptable to many similar small hydro sites.

Hydro Addition

The hydro addition, consisting of a new intake, powerhouse, and turbine/generator unit, was placed in the narrow space between the replaced spillway gates and the old powerhouse. As a result, demolition was minimized, and the same cofferdam system served both the renovation and hydro work. Because of the close quarters, the new structures incorporated elements of existing structures, which further reduced design and construction costs.

Intake Structure

The new intake structure was based on our previous design for the new spillway tainter gate structure and was placed immediately adjacent to the spillway. The tainter gates had

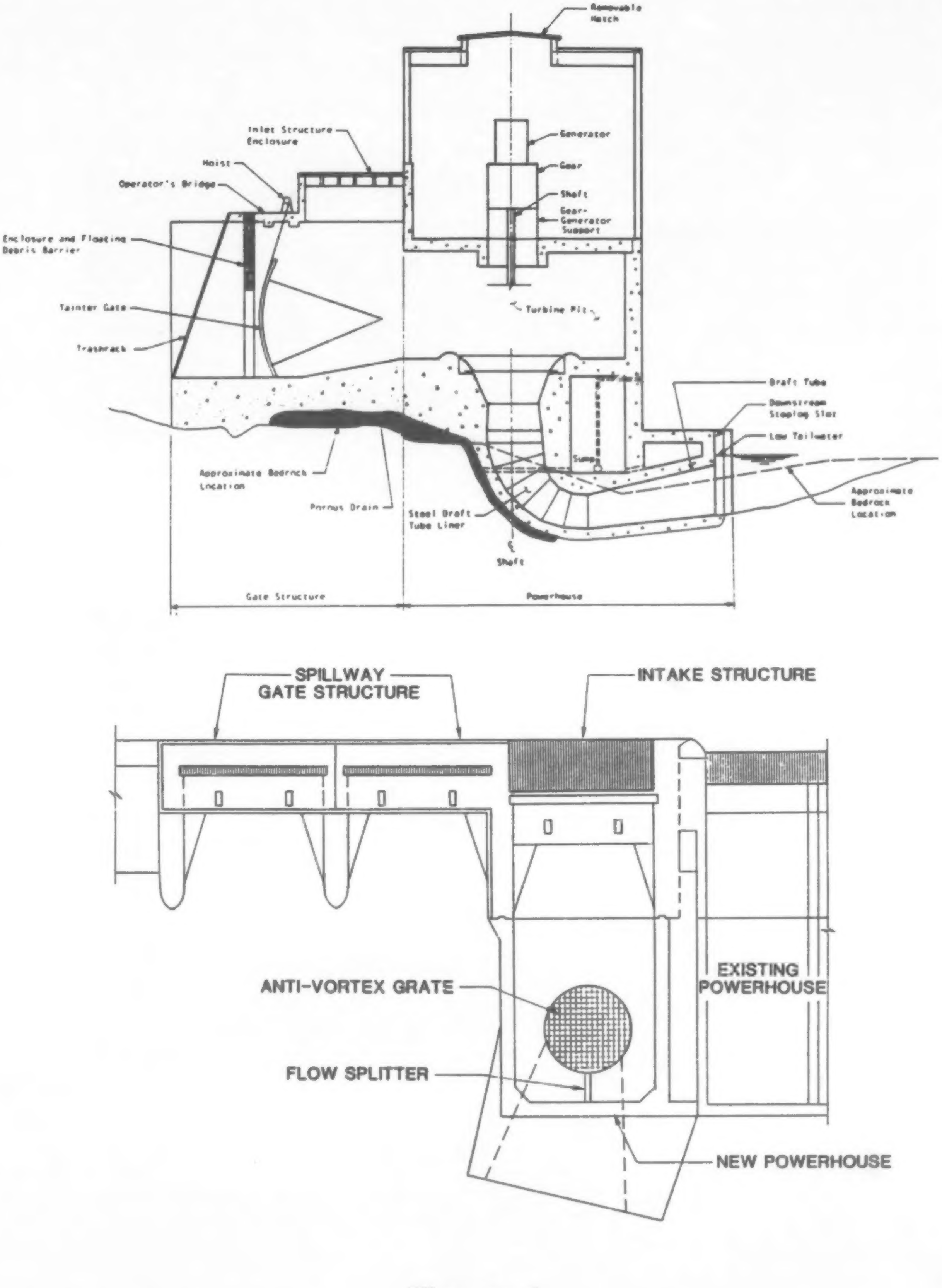
Removable Hatch
Inlet Structure Enclosure
Generator
Hoist
Gear
Operator's Bridge
Shaft
Gear-Generator Support
Enclosure and Floating Debris Barrier
Tainter Gate
Turbine Pit
Trashrack
Draft Tube
Downstream Stoplog Slot
Low Tailwater
Sump
Approximate Bedrock Location
Porous Drain
Steel Draft Tube Liner
Approximate Bedrock Location
℄ Shaft
Gate Structure
Powerhouse
SPILLWAY GATE STRUCTURE
INTAKE STRUCTURE
EXISTING POWERHOUSE
ANTI-VORTEX GRATE
FLOW SPLITTER
NEW POWERHOUSE

Figure 1

NEW POWERHOUSE SECTION

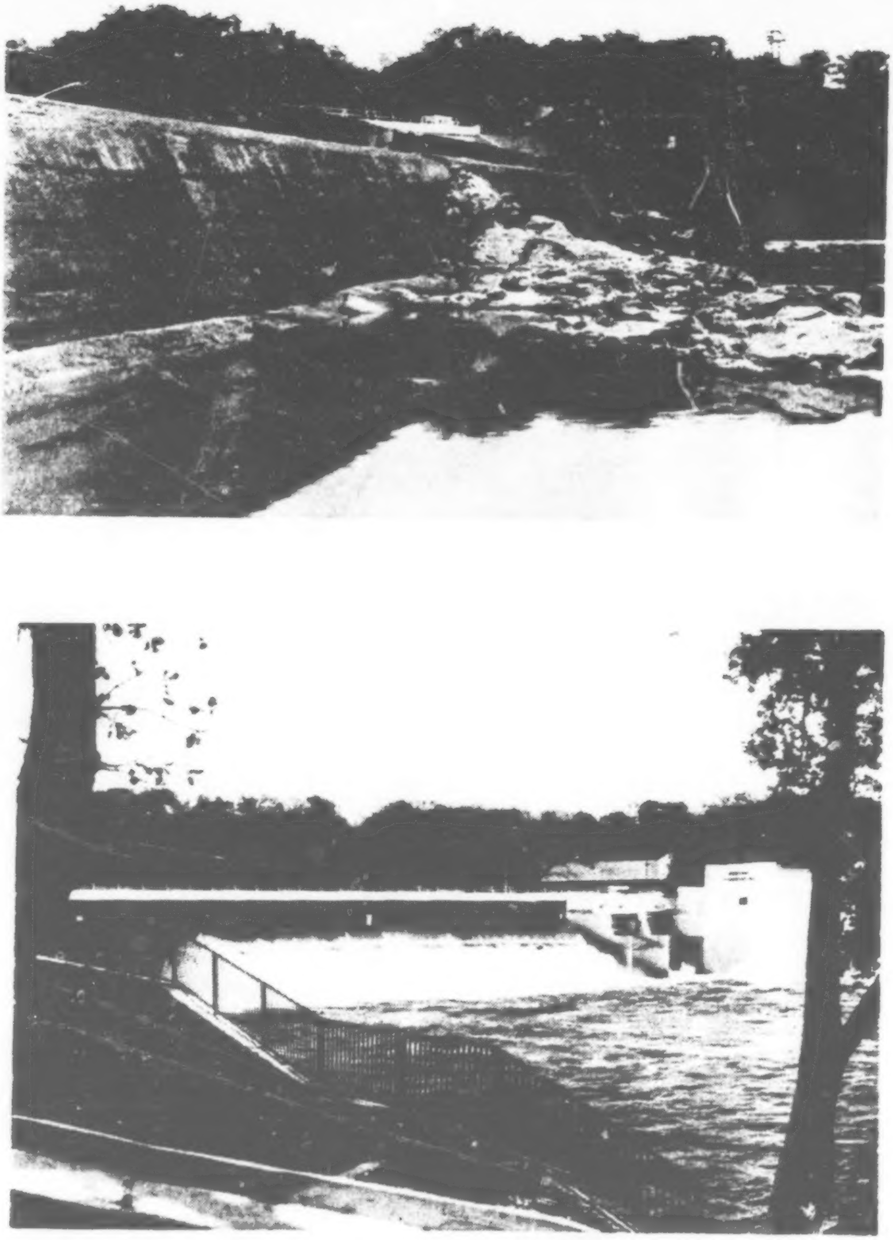

Figure 2
BEFORE AND AFTER PROJECT

been designed as part of the dam renovation to replace the wooden slide gates, which were deteriorated, structurally deficient, and hard to operate. Using the available tainter gate design for the new intake cut engineering, manufacturing, and construction costs by more than 20 percent.

The intake and spillway gate structures shared numerous design considerations to trim costs. For example, we used a radial or tainter gate with sloped gate arms, ribbed skin plates, and an efficient cylindrical shape. They are reliable, provide a large intake area, and require a relatively small hoist capacity.

For the gates' concrete control structures, we used post-tension rock anchor technology which took advantage of the site's mass of durable granite bedrock. Also, the post-tensioning substantially cut costs by reducing the amount of reinforcing and volume of concrete.

A post-tension trunnion anchorage system was employed to allow the use of high-tension steel. We used a solid stainless steel shaft for the trunnion pin. This simple system has often been successful and is much less expensive than the more detailed trunnion beam systems common at larger-scale projects.

Another advantage of the post-tensioning/trunnion anchorage is that it maintains the concrete in compression and eliminates the cracking that can develop from shrinkage, bending, and large concentrated stresses at the trunnion. Slowing the rate of deterioration will thereby reduce maintenance and increase the life of the gate structures. Figure 3 illustrates the new tainter gate section.

Open Flume Turbine Pit

We selected an open flume setting for the new turbine/generator unit to allow uncomplicated wall construction and reduce the turbine equipment weight and cost. The open flume concept was particularly advantageous because it was compatible with the intake structure and the adjacent older powerhouse, which also has a vertical turbine and open flume system.

However, the open flume setting can cause vortex formation. To address this problem, the turbine manufacturer (Ingersoll-Rand) conducted hydraulic model studies as part of their equipment development. Based on these studies, Barr Engineering then designed an efficient splitter wall and anti-vortex grate (see Figure 1). The wall and grate direct the flow of water similar to a scroll case but without the complicated formwork and structural system.

The new system reduced the total head loss by approximately 2 percent when compared to the manufacturer's previous system. This represents a significant improvement to an existing turbine machinery design.

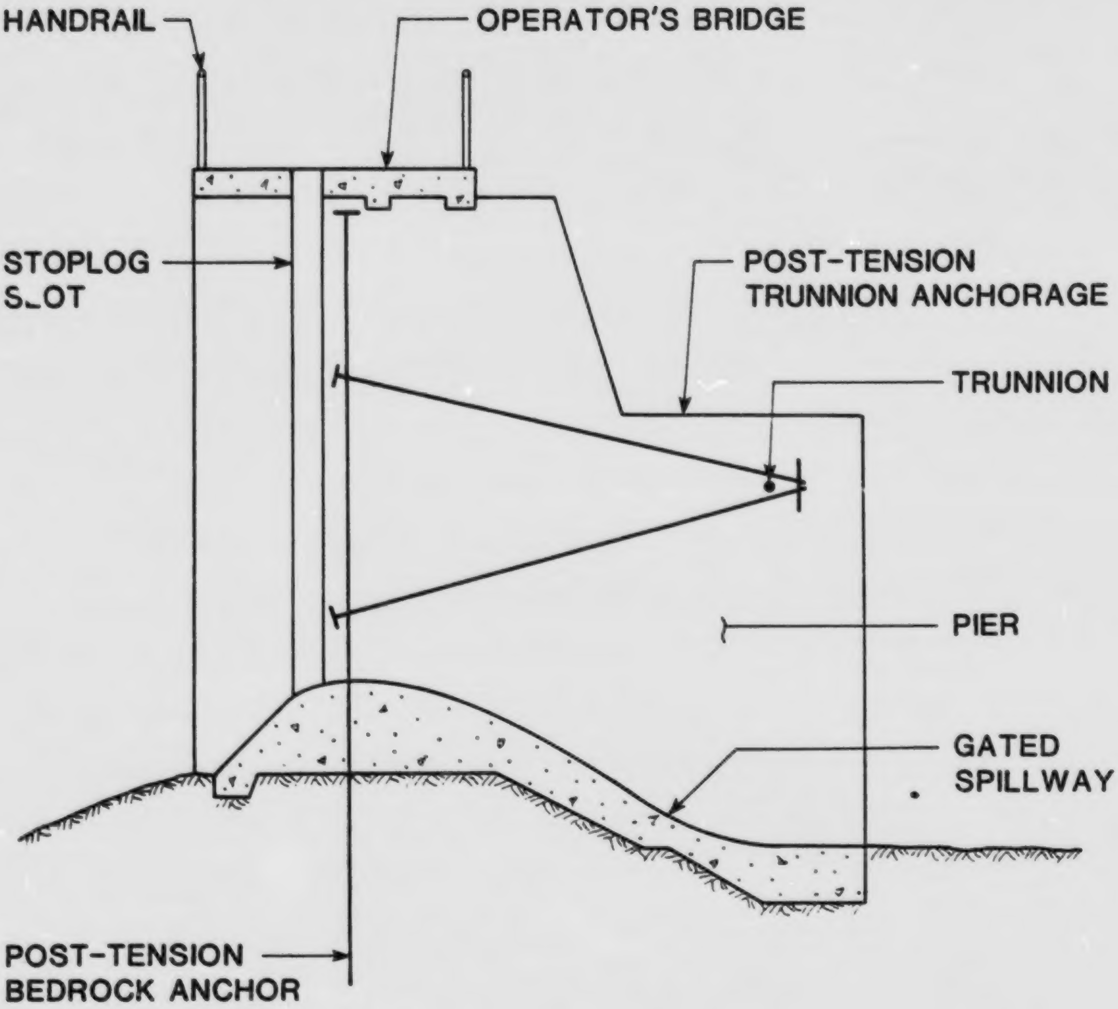
HANDRAIL
OPERATOR'S BRIDGE
STOPLOG SLOT
POST-TENSION TRUNNION ANCHORAGE
TRUNNION
PIER
GATED SPILLWAY
POST-TENSION BEDROCK ANCHOR

Figure 3

NEW TAINTER GATE STRUCTURE SECTION

Turbine/Generator Unit

To cost less and be compatible with the open flume setting, the turbine/generator unit consisted of a standardized vertical fixed blade unregulated turbine with a speed increaser and induction generator. (See Figure 4.)

This type of unit is based on Ingersoll-Rand's pump and motor technology, which has proven successful for small-scale projects. The unit is substantially less expensive and allows the use of existing manufacturing capabilities and equipment. In addition, the turbine can be manufactured, tested, shipped, and installed with a minimum of embedded parts.

The gear and generator were located on a removable steel beam and open grating floor system. This allows the turbine, vanes, runner, and other components to be directly observed when the tainter gate is down and the turbine pit is dry. The startup and flow to the unit can also be directly observed when the unit is operating. This simple, visible system facilitates ease of operation and maintenance, and provides the operator and even the casual observer a unique awareness of the purpose and method of operation of each component.

The powerhouse addition has a removable roof for installation of the turbine/generator unit, which eliminates the need for a powerhouse crane. Figure 5 illustrates the gear and generator on the open grating floor.

Automated Data Collection
and
Analysis for Hydro Turbine Testing

By
L.M. Polsky

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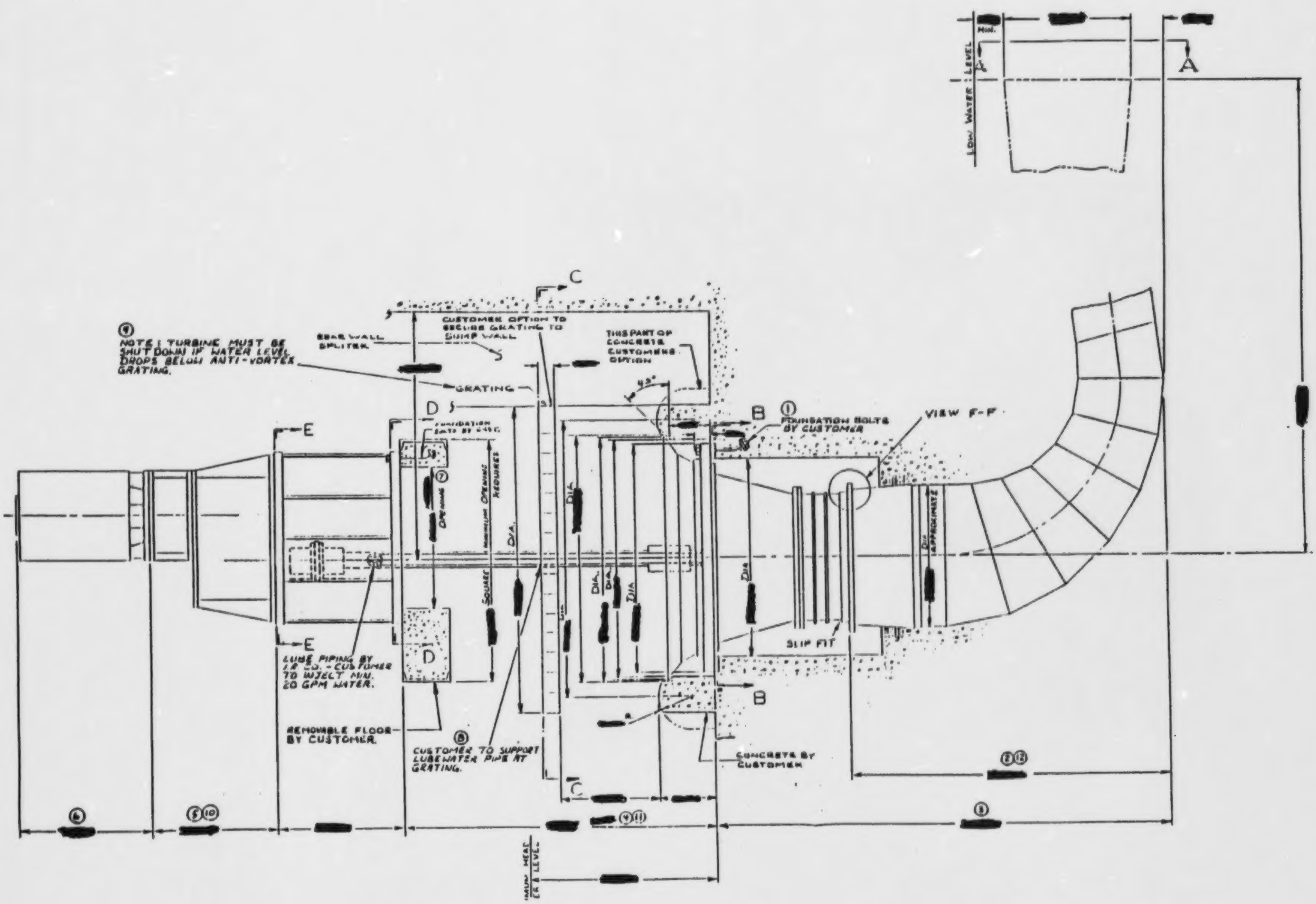
⑨ NOTE: TURBINE MUST BE SHUT DOWN IF WATER LEVEL DROPS BELOW ANTI-VORTEX GRATING.
REAR WALL SPLITER
CUSTOMER OPTION TO SECURE GRATING TO SUMP WALL
THIS PART OF CONCRETE CUSTOMERS OPTION
45°
GRATING
C
D
E
B
① FOUNDATION BOLTS BY CUSTOMER
VIEW F-F
FOUNDATION BOLTS BY CUST.
⑦
OPENING
MINIMUM OPENING REQUIRED
SQUARE
DIA.
DIA
DIA APPROXIMATE
SLIP FIT
LUBE PIPING BY I.R. CO. - CUSTOMER TO INJECT MIN. 20 GPM WATER.
REMOVABLE FLOOR BY CUSTOMER.
⑧ CUSTOMER TO SUPPORT LUBEWATER PIPE AT GRATING.
CONCRETE BY CUSTOMER
R
A
LOW WATER LEVEL
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Figure 4

TURBINE/GENERATOR INSTALLATION

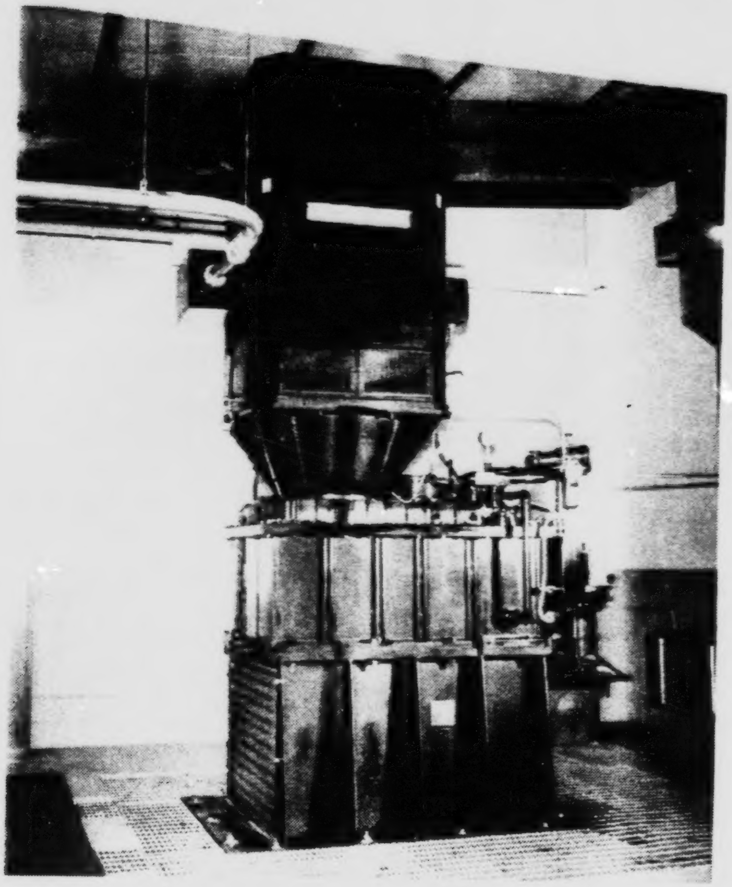

Figure 5
GENERATOR AND GEAR

Construction

The hydro addition was relatively simple and straightforward to construct. The most significant problem was the sudden formation of frazzle ice during an extremely cold Minnesota December and high early winter flow conditions. The construction sequencing is listed below.

1. Construction of upstream braced sheetpile cofferdam and downstream earthfill cofferdam
2. Demolition of deteriorated spillway gate structures
3. Construction of spillway gates and intake structure
4. Removal of upstream cofferdam
5. Excavation of granite bedrock for draft tube
6. Successive concrete construction extending from foundation drains, draft tube, turbine level, and turbine pit
7. Installation of completely assembled turbine unit
8. Construction of powerhouse floor and superstructure
9. Installation of gear and generator
10. Startup

The completed powerhouse is approximately 26 feet wide, 74 feet long, and 60 feet high (from draft tube to roof). The structure was excavated 12 feet into the bedrock foundation.

SUMMARY

Every hydro project has a full set of site-specific characteristics to consider when designing a hydro addition. The Granite Falls hydro system can be especially effective when adapted to a dam having any of the following:

- Low head (15 to 30 feet)
- Low flows (400 to 1,600 cfs)
- Small capacity (500 to 1,500 KW)
- Limited space for development
- Existing tainter gate spillway
- Existing variable turbine generators and vertical turbine arrangements
- Fast-track schedule or remote location -- in this case, most of the powerhouse work can be completed before the pre-assembled and tested turbine unit arrives to be merely set and bolted in-place
- Uncomplicated or obvious construction, operation, and maintenance procedures are desired

Most of these factors are common to small dams constructed decades ago on mid-sized streams. Because of their age, these facilities are especially in need of repair and modification.

The goal is to creatively combine hydro improvements with dam renovation while adapting to site-specific conditions. Proof of success lies in the Granite Falls Dam, where this approach resulted in a valuable increase in hydropower which otherwise would have been impossible for the town.

SESSION 14:

PLANT REHABILITATION

Chairperson: R. Wright
Ontario Hydro

A Systematic Approach to Turbine Rehabilitation

By
D.H. Ross, A. Mohino

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A SYSTEMATIC APPROACH TO TURBINE REHABILITATION

David H. Ross*
Alfredo Mohino**

ABSTRACT

A growing number of power producers are looking toward equipment suppliers, for direction and advice, regarding there best approach to rehabilitation of existing equipment.

With the current demand in this area, comes the need for a systematic, and cost effective approach towards achieving optimal results with respect to; i) limiting project downtime, ii) reducing maintenance requirements, iii) upgrading power production and efficiency.

Typical rehabilitation projects involving Francis, Kaplan or Propellor Installations for example, have an approximate duration of ten(10) to twelve(12) months, depending on the extent of component replacement, number of units, and scope of civil/structural rework. This time frame can be tailored to include all the pertinent steps, from the initial site study and unit inspection, tendering process, equipment manufacturing, delivery and start-up with limited economic pressure on the customer. With detailed planning, and timely execution, by an experienced project team the outcome can be mutually beneficial to both customer and supplier.

This paper will illustrate an organized approach to a rehabilitation project. Each step will be discussed at length, highlighting actual methods applied, typical customer concerns, application of computer software , interface problems, coordination of mechanical, hydraulic, and civil aspects, as well as other related topics.

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INTRODUCTION

With the high cost of new equipment and new civil/structural construction work, coupled with a general desire to minimize the overall project schedule, rehabilitation of existing hydroelectric installations has become an attractive alternative to developing new power plants.

Many abandoned hydro stations, after having been idol for several decades, have over the past decade, become the focus of attention for many developers, entrepreneurs, and Public Utilities.

These inactive stations, as well as many others, still in operation, are continually being studied to determine specific needs and economic feasibility of a Rehabilitation program. Requirements for rehab of such stations, obviously will vary with type and age of existing units. The existing physical condition of the units may dictate only cleaning and minor repair, whereas others may require component replacement. However, in addition to this, we must also factor in the owner/operators wishes with respect to operating characteristics, unit maintenance, and desired upgrade in power output which will also influence the scope of work.

It is therefore, important that the customer establish a list of objectives, highlighting key areas of desired improvement, prior to embarking on a rehabilitation project.

In all cases, site inspection is essential in evaluating unit requirements for rehabilitation. These inspections can generally be carried out with minimal unit disassembly, allowing for preparation of budget costs and a preliminary scope of supply. However, it is advisable to dismantle the unit to it's fullest practical extent, thus allowing safe and accurate inspection, and providing data suitable for preparation of firm estimates and procurement of raw materials after contract award. A comprehensive inspection plan is the best insurance against surprises during manufacturing and installation.

With organized planning and proper application of resources, a small hydro rehabilitation project can be a success.

PLANNING & SCHEDULING

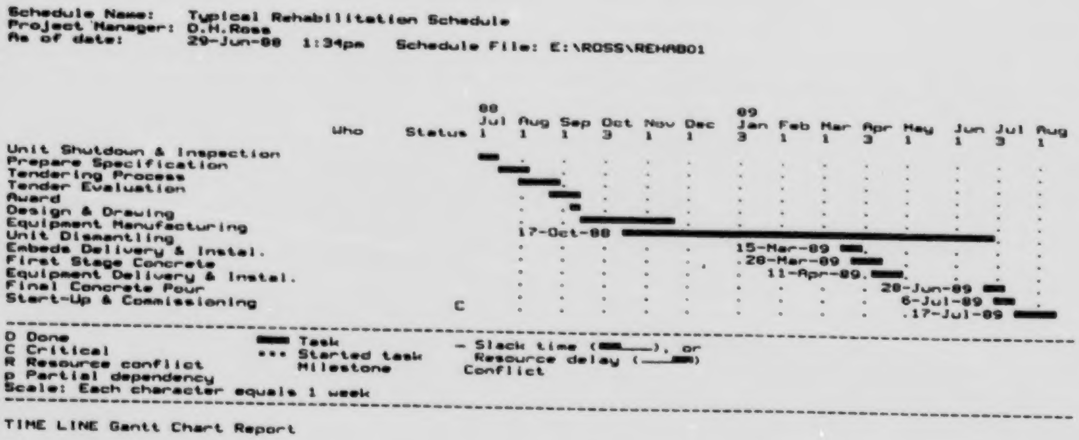
In order to ensure that all aspects of a rehabilitation project are adequately covered, it is important to have all pertinent personnel involved at the planning & review stage. Thorough planning is the main ingredient in the success of any project. It is particularly important to include operating & maintenance personnel at this stage, as they are the most familiar with individual operating characteristics and specific maintenance concerns of the units in question. They will be best suited to recommend specific improvements, in relation to past operating experience, and reoccurring problems.

The goal here is to determine the basic objectives of the rehabilitation program thereby establishing a general scope of supply prior to detailed inspection. To this end, the following is a suggested review list for consideration:

1. Reduction of unscheduled unit downtime, through the application of a suitable maintenance program. Thought should be given to the addition of exterior gauges or measuring devices allowing for measurement of concealed or submerged bearings and wear surfaces without the need for unit shutdown.
2. Eliminating specific problems of component failure such as cracking, cavitation, and excessive wear, by the application of proper materials, and design or wear applicable a suitable repair procedure.
3. Increasing unit output and efficiency through an individual, or a combined modification to runner, wicket gate, draft tube or intake characteristics.
4. Extending service life by selection of quality materials and the restoration of proper running clearances to provide for smoother operation. Structural or cosmetic repairs, or improvements to the powerhouse, intake or tailrace may also be in order.

This review list is a guideline for operating and maintenance personnel, however it is recommended that they engage the services of an experienced manufacturer or consultant in the field of hydroelectric rehabilitation. They can provide specific historical data that can benefit the overall approach to a given project.

Once the general objectives have been set, a schedule should be produced to establish all pertinent milestones in the rehabilitation project from unit shutdown & inspection to start-up & commissioning. Thus, providing an organizing tool to monitor and track the overall Project Plan. There are several means of scheduling available to the Project manager today. One suggested scheduling tool is the TIMELINE PROGRAM by Breakthrough Software Corp., which provides the capabilities of coordinating all necessary tasks, required to complete the project on time. An example of a typical rehabilitation schedule would be as shown (see Figure 1). The example shown highlights the basic milestones that may exist in the project schedule. This can also be expanded for the manufacturing stage, to indicate all production phases, including task dependencies, allocation of resources, conflicts in activities etc. This program is a fast tracking system, which will provide up to date project status reports when used to its potential.



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Schedule Name:    Typical Rehabilitation Schedule
Project Manager:  D.H.Ross
As of date:       29-Jun-88  1:34pm   Schedule File: E:\ROSS\REHAB01

                                                  88                          89
                                                  Jul Aug Sep Oct Nov Dec     Jan Feb Mar Apr May  Jun Jul Aug
                                   Who     Status 1   1   1   3   1   1       3   1   1   3   1    1   3   1
Unit Shutdown & Inspection
Prepare Specification
Tendering Process
Tender Evaluation
Award
Design & Drawing
Equipment Manufacturing
Unit Dismantling                                      17-Oct-88
Embeds Delivery & Instal.                                                     15-Mar-89
First Stage Concrete                                                          .28-Mar-89
Equipment Delivery & Instal.                                                     11-Apr-89.
Final Concrete Pour                                                                       28-Jun-89
Start-Up & Commisioning                        C                                             6-Jul-89
                                                                                            .17-Jul-89
-----------------------------------------------------------------------------------------------------------
D Done                       Task              - Slack time (     ), or
C Critical               ... Started task        Resource delay (     )
R Resource conflict          Milestone         Conflict
p Partial dependency
Scale: Each character equals 1 week
-----------------------------------------------------------------------------------------------------------
TIME LINE Gantt Chart Report
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<u>**FIGURE 1**</u>

UNIT SHUTDOWN & INSPECTION

It is common for any customer to be reluctant to shutdown and disassemble for any length of time . However, in fairness to the manufacturer or consultant, and in the best interest of the customer, disassembly of the existing units should be made to an extent suitable for a complete visual and/or dimensional inspection of the following checklist: Photos also provide a good record of existing conditions and should also be included in the inspection.

1. Hydraulic passages including runner, wicket gates, stay vanes, distributor faces and discharge and area; full dimensional verification and visual check for cavitation and cracking.
2. Main Shaft, bearings, and seals; dimensional verification; note excessive wear.
3. Wicket Gate & linkage system clearances.
4. Wear ring seal clearances.
5. Note areas for hydraulic improvement in the intake and tailrace that may enhance flow characteristics.
6. Draft Tube dimensional verification.
7. Condition of existing hardware such as seals, packing, fasteners etc.
8. Note any constraints with respect to civil/structural interface, handling capacity, physical layout of station and entrance doors etc.
9. Note existing generator & speed increaser data.

With a detailed inspection, properly documented, preparation of the technical specification should be a simple task.

PREPARING THE SPECIFICATION

The first task in preparing the specification is to establish a rational level of expected performance based on site inspection data available. A theoretical potential of station output can be determined by use of flow data collected from the operator or government department. Based on this data a Maximum level of annual energy production can be set.

Finally we must review the electrical, mechanical and hydraulic factors that may limit this level of production and determine the economic feasibility of improvement. The following is a standard list of areas that should be considered in this review:

1. Intake Conditions: can excessive velocities be reduced; can flow area be increased; do trash racks need improvements; are other improvements in hydraulic conditions called for, such as straightening of intake, removal of rocks or other obstructions etc.
2. Flume, pressure case, spiral case etc.: do poor hydraulic characteristics exist in these areas. Some modifications can be made here with relatively low costs. However, others will be too costly and may not represent a favorable cost/benefit ratio.

3. Draft tube and tailrace: this area is of considerable importance particularly in low head installations. Enhanced performance may be achieved through modifications in one or both.
4. Electromechanical: is a generator rewind in order and if so what increase in output is achievable; what is a safe max. runaway speed for the generator. This is a critical aspect especially when rehabilitating Kaplan, Propeller, & high unit speed Francis applications. It is therefore essential that original generator data be verified through existing records.
5. Existing bearings capacity: must be compared with expected hydraulic thrusts of contemporary runners.
6. Main shaft capacity: if not sufficient, is it viable to replace?
7. Existing unit setting with regards to tailwater elevation: must determine a safe maximum output with respect to cavitation concerns.

Having established these parameters, a safe level of output can be estimated. Secondly, reasonable, and attainable levels of efficiency must be established based on hydraulic conditions, and the age of the unit. The specification writer must evaluate the possibility of testing the efficiency to an accountable degree, and he must have a firm grasp of the costs of doing so. A penalty clause, if included here is an unacceptable alternative and may force competent manufacturers to decline.

In summary, when writing a specification, allowance must be made for the capability of enforcing it, and consideration must be given to an equipment supplier with a successful record in unit rehabilitation. It should be noted, that far more energy is lost through late deliveries, and downtime due to repair of cavitation damage, and component failure such as cracking, fracture etc.., than by a loss of ten points in efficiency.

A good specification is fundamental in attracting competent and capable suppliers. Too much emphasis on customer protection may have the opposite effect than that originally intended.

MANUFACTURING

The manufacturing stage of any rehab project can be organized, and executed efficiently, and on time by applying the following basic steps:

1. Thorough and accurate match marking and identification of all existing components at unit dismantling.
2. Verification of complete contract scope after award.
3. Detailed scheduling of contract supply, highlighting critical path items and defining necessary lead times for all components.
4. Suitable in process Quality Assurance on all components, including cleaning and non destructive testing of questionable items.
5. Satisfactory shop assembly to verify component fits.

A successful project conclusion can be realized when these simple steps are applied by an experienced project team.

WARRANTY

In general terms, for small hydro a full efficiency test is not warranted. However, when conditions are favorable, an index test is desirable. In the case where hydraulic considerations do not lend themselves to an index test, maximum power output guarantees complimented with an average annual energy production, based on flow exceedence curves should be adequate.

SLIDES - EXAMPLES OF PAST REHABILITATION PROJECTS

CONCLUSION

Rehabilitation of existing equipment is generally a less time consuming and more economical alternative to development of new installations.

Given the detailed and systematic approach discussed here, a rehabilitation project of any magnitude can and should, be a mutually rewarding exercise by customer, consultant and equipment supplier.

The overall emphasis, however must be placed on the need for timely execution, and mutual cooperation of all parties involved.

Aswan High Dam Project, Turbine Rehabilitation/Modernization

By
R.J. Grigera

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ASWAN HIGH DAM PROJECT, TURBINE REHABILITATION/MODERNIZATION

Presented by: Roberto J. Grigera,
Voith Hydro, Inc.

Presented at: Small Hydro '88,
Toronto, Ontario, July 4-8, 1988

INTRODUCTION

The legendary Nile River around which Egypt built its magnificent past, has also been intimately associated with the Country's modern development. The river was tamed by the force of man near Aswan (some 900 km south of Cairo), initially at the turn of the century through the construction of what is now called the Low Dam and more recently, during the sixties by the High Dam Project, 10 km upstream of the first dam.

Thanks to these projects, in particular the High Dam, Aswan, once famous for its granite which was quarried for many of Egypt's monuments, tombs, and obelisks has become the main source of electric energy for Egypt, generating approximately 25% of the country's consumption.

The High Dam powerplant, built at the foot of a 41 x 10^6 cubic meters earth filled dam, houses 12 Francis-type hydro turbine/generators supplied by L.M.Z. and Electrosila, both from Leningrad, U.S.S.R. The rating of these units is as follows:

Turbine Rated Output:	180 MW
Speed:	100 RPM
Rated Net Head:	62 M

The planned average annual energy for the plant was 10,000 GWH/year.

The energy generated at 15.75 KV is stepped up to 500 KV at which voltage it is transmitted to the main consumption centers in Egypt.

PROBLEMS ASSOCIATED WITH THE ORIGINAL TURBINE RUNNERS.

After several years of operation, the owner of the plant, the Egyptian Electricity Authority (E.E.A.) decided to investigate the feasibility of rehabilitating the units to correct problems with the original runners and to generally return the units to as new condition following many years of operation.

Additionally, based on proposals received from Allis-Chalmers, it was apparent that the original runners could be replaced with new runners offering a significant increase in operating efficiency.

As a consequence, in June of 1982, the owner signed a contract with Allis-Chalmers Corp. (now Voith Hydro, Inc.) for the rehabilitation and modernization of the Aswan High Dam turbines.

The work involving the various aspects of this challenging project began immediately after execution of the contract. Very demanding schedules were followed toward re-commissioning the units at the earliest possible dates. The project teams of E.E.A. and Voith Hydro responded to the challenge of the project not only because of the obligations arising out of the contract but also because of the need to minimize equipment outage.

EXTENT OF THE REHABILITATION AND MODERNIZATION WORKS

While the impetus to the turbine rehibilitation project came from the decision to replace the runners with the necessary adaptation, the project was expanded to also include the following:

- Replacement of the governors by modern state-of-the-art systems, electronically operated, incorporating a new modern joint control feature. Pumping units, pressure tanks and the air supply systems were found in good condition.
- Replacement of the original grease lubricated gate system by self-lubricated wicket gate bushings.
- Replacement of the first two sets of wicket gates (i.e. 48) due to the time involved in the journal machining operation.
- Complete replacement of all gaskets and seals.
- Full blasting and coating of the water passage surfaces using coal tar epoxy.
- Another major item of work came about when the first generators were dismantled. An inspection of the stators revealed that they needed re-wedging, as many of the slots had loose coil wedges. Correspondingly new wedges, slot sticks and filler material, as well as all necessary tools and expendable materials required and the associated field work were added to the original project scope.

PARTICULAR CONDITIONS AND SCHEDULE FOR THE WORK.

Due to the importance of the High Dam powerplant in Egypt's electric energy scheme, the outage times for the rehabilitation had to be minimized. No more than two units could be worked at one time. The field work was scheduled to enable completion of the rehabilitation work for each pair of units, both fed by the same penstock, in an average time of 10 months.

Between the work in one pair of units and the next, a maintenance period of 2.5 months had to be accommodated to allow compliance with E.E.A.'s preventative maintenance program covering the full inspection of a given pair of units per year. This lack of continuity in the work from one pair of units to the next is a peculiarity of this project that not only alters the rhythm of the works, but also contributes highly to the length of the project (i.e. first recommissioning by the beginning of 1986 and the last one planned for the end of 1991).

Field labor is procured from an installation sub-contractor with a number of skilled maintenance personnel seconded by the owner.

Figure 1 shows the details of the field work schedule for each pair of units.

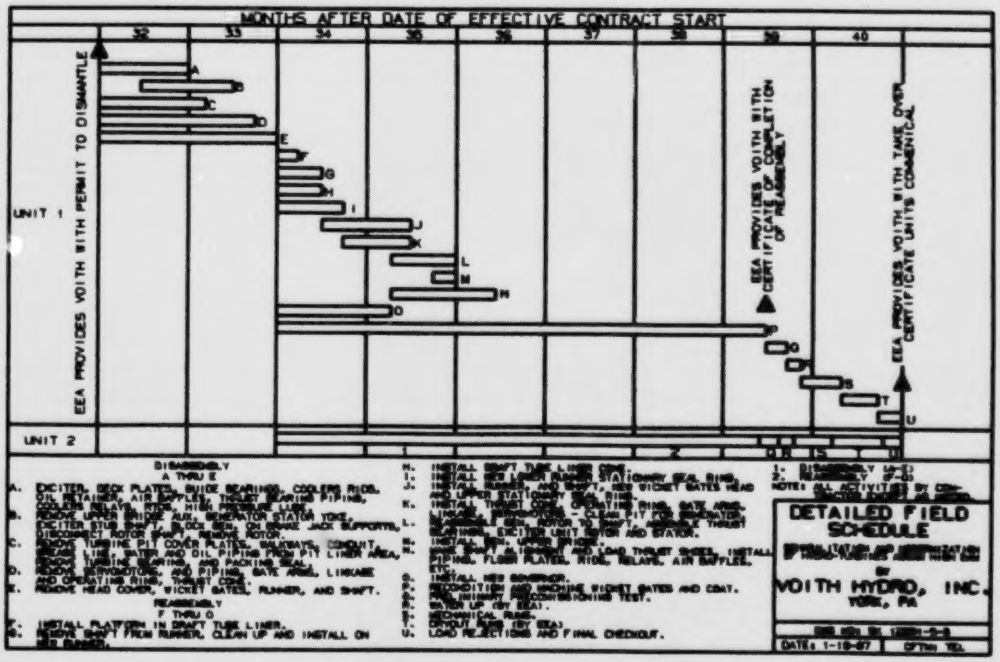


Figure 1 - Schedule for one pair of units.

TRANSPORTATION

Transportation of the new 6500mm diameter, 130 metric ton stainless steel runners from York, Pennsylvania to the Aswan site constitutes a task of major proportions requiring a great deal of planning and coordination. Each of the 3 stages (i.e. York to Baltimore, Baltimore to Alexandria, Alexandria to Aswan) has special conditions, requirements and considerations.

For the inland transportation from York to Baltimore, a special 96 wheel rig which weights 100 tons, is used. The 90 km trip takes about one week. The loading of the runner on the ocean freighter is done by a large capacity port crane. After an approximate 30 days of travel the runner is ready to be loaded on a river barge at the port of Alexandria. This operation is either done by a large floating crane (i.e. 200 ton capacity) or by means of the boats own cranes depending on the freight ordered. The loaded barge is then tugged through the Nile River to Aswan in a journey that takes around 1.5 months, time depending on the water condition of the river. At Aswan, the High Dam powerhouse building has a special dock below the assembly area (with hatch opening) to allow reach by the powerhouse cranes to lift the runner and its stationary wearing rings. Figures 2 and 3 show sequences of the transportation of a runner. The total amount of time taken for each runner between York and the site is between 3.5 and 4 months.

Figure 2 -

Runner on special rig for inland transportation to the Port of Baltimore

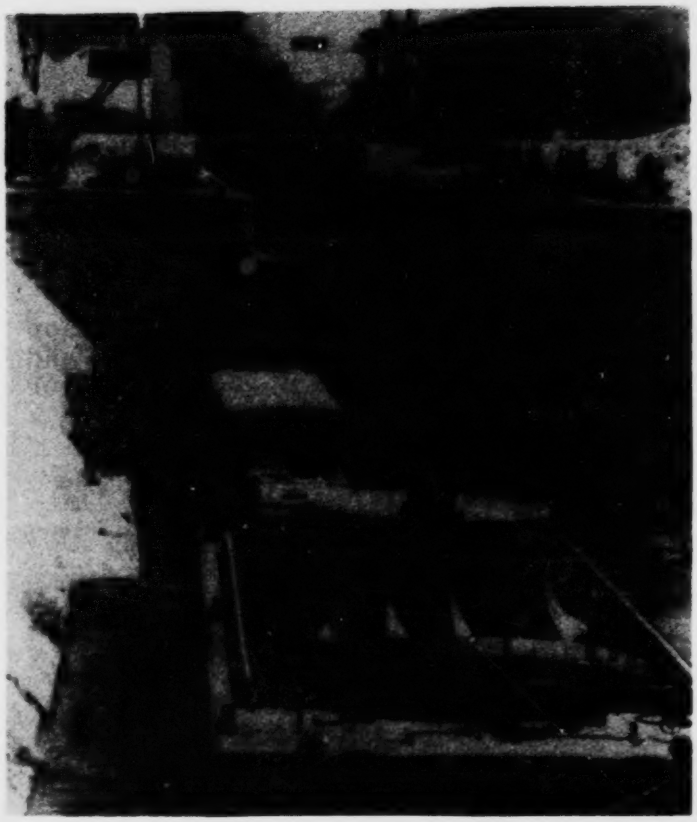


Figure 3 -

Tug pulls the barge up the Nile River approaching the Aswan Low Dam locks.

DESIGN AND MANUFACTURE OF THE NEW RUNNERS

The new High Dam runners were designed by the application of the most modern design techniques. The task involved was one of major proportions in which a replacement runner designed to achieve state-of-the-art levels of efficiency would perform substantially free of cavitation while fitting into the existing water passageways and the mechanical envelope defined by the original machines.

Reflecting the current state-of-the-art, the hydraulic design is substantially different from the one used in the original manufacturer's runners. As an example, in order to improve the hydraulic performance the band length of the new runner is substantially longer than the original, while the discharge diameter of the new runner is significantly smaller to accommodate the band. Due to these changes, the draft tube cone was modified by means of a cone insert.

Another particular aspect of the new runner design is a larger entrance diameter to improve the hydraulic loading. This change is accomplished by removing large portions of the bottom

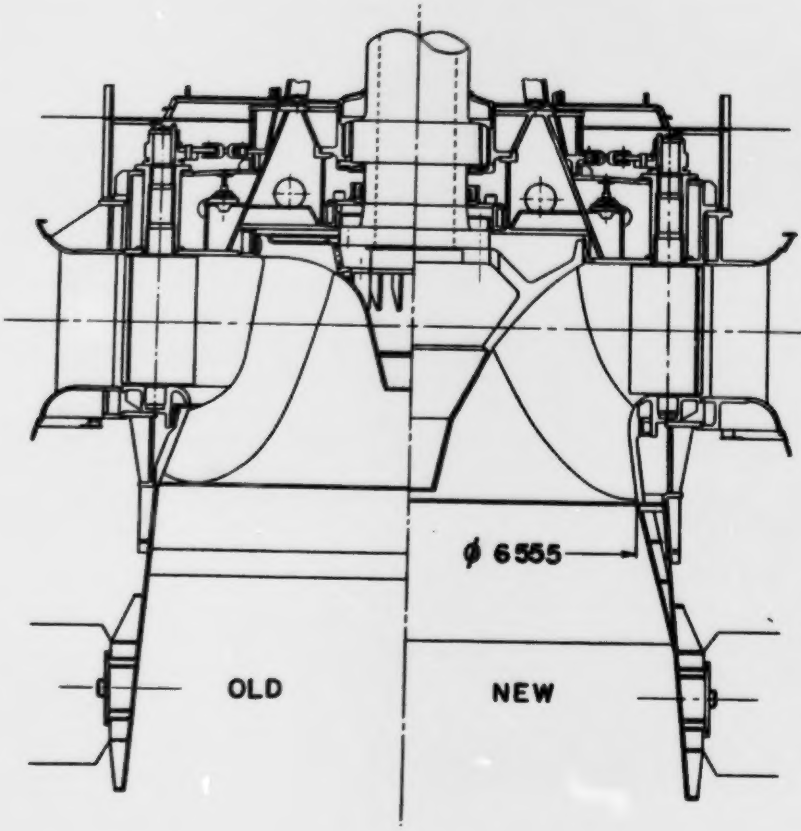


Figure 4 - Comparison of old and new runner designs

ring curved lip through field machining. The comparison of both runner designs is shown in Figure 4.

High powered computer programs provide the basis for a careful three dimensional stress analysis of the runner; in addition, a three dimensional finite element analysis of the flow through the water passageways, allowing full view of the velocity field and pressure profiles on the blade surfaces, was the basis to generate the model runner hydraulic design. Following optimization through model testing in the hydraulic laboratory, it showed excellent overall cavitation performance over the entire design range and an efficiency several percent above that of the original runners was predicted for the prototype. The expected prototype performance curve, based on model data, is shown in figure 5. Accurate duplication of the model geometry in the proto-type blades was achieved by utilizing the same numerical control (NC) definition for machining the large blades as had originally been used to machine the model runner.

In the mechanical design, a mathematical model was used to verify the structural integrity of the runner. By means of a finite element analysis program, stresses were mapped and evaluated as shown on figure 6. Particular interest was placed

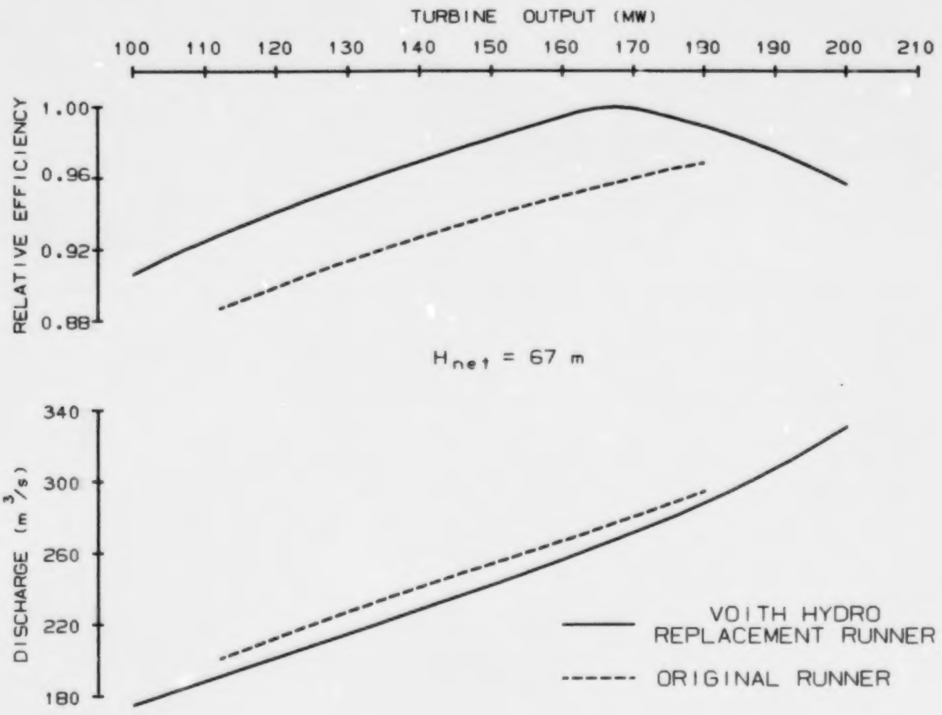


Figure 5 - Expected prototype performance improvement.

in analyzing the area of the blade to crown connection, as this is the location of the highest stresses at maximum power generation.

For all possible loading conditions, structural deformations as well as the expected cycles regarding fatigue damage were studied in detail.

The effect of forcing frequencies, such as running speed, Rheingans and Von Karman vortices, which could create resonant conditions and thus decrease safety margins against fatigue or crack growth damage, were thoroughly analyzed with confirmation that no critical excitation was predicted for these runners. Also, as a result of the life cycle analysis carried out, a minimum of 50 years of safe life was predicted.

The material selected for the runners was ASTM A487 CA6NM stainless steel, 8,400 kg/cm² tensile strength which has good cavitation resistance properties.

Each runner has 13 cast buckets which were machined to true dimension with a 10" diameter ball cutter final pass; as indicated previously, the same "NC" definition as used to machine the surface of the model runner blades was used for this operation.

Further finishing of the bucket surface took place by means of belt grinders to remove the peaks left by the milling tool.

The runner crown was cast in two parts which were then welded together circumferentially.

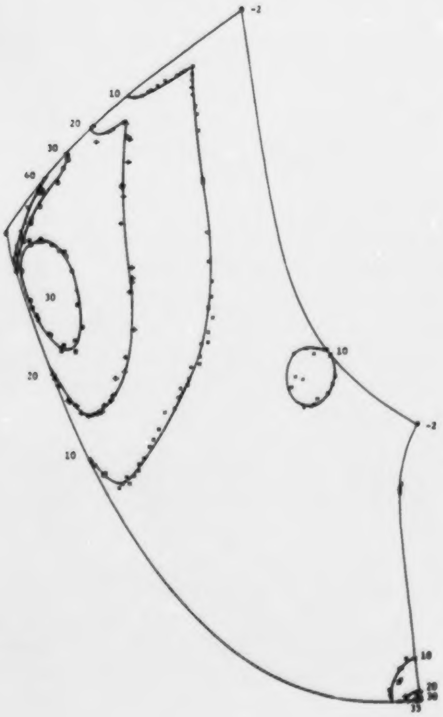
The band was fabricated using ASTM A487 CA6-NM specially rolled plates made out of melted electroalloy ingots. Shop welding of the various joints was done by the electroslag process as was also the case of the bucket to crown and band joints.

This application was the first one in which electroslag welding was developed for the CA6-NM stainless material.

A special weld positioner was designed and built to permit the electroslag welding of the bucket to crown and band joints, which must be done with the actual weld joint in the vertical position. Figure 7 shows this operation.

Twelve inch long copper shoes with built-in fillets were used at each side of the joints. Each pair of shoes suits only one 12" long position of the joint configuration.

Consumable nozzles to carry the weld wire (as many as 3 nozzles in the largest joints) were set in the best disposition for each case.



ASWAN HIGH DAM
RUNNER BUCKET

Stress contour plot showing lines of constant maximum principal stress (MPa) during operation at rated power (180 MW)

Figure 6 - Stress contour plot of runner bucket

Figure 7 -

Specially designed weld positioner for electroslag welding.

A deposition rate of 15 lb./hr./wire of 410 NiMo weld material is obtained with this weld process at 42 to 50 V.D.C. drawing about 500 Amp current.

Bucket to crown welds are made first followed by stress relief before the bucket to band welds are made.

The final stress relief process takes place before machining of the fully fabricated runner.

Machining takes place with the 25' (7.66 m) 254 TN capacity vertical boring mill. Tolerance within .002" at the wearing ring areas is achieved. Figure 8 shows this operation.

TOOLS, EQUIPMENT AND SUPERVISION OF THE FIELD WORK

Important pieces of equipment are required for the field work. The majority of these tools was delivered to the Aswan site under the rehabilitation contract. The most important items listed below:

1	1.2 m swing x 4.5 m between centers engine lathe for machining the wicket gate journals to fit new stainless steel sleeves.
1	5 TN capacity jib crane to feed the lathe with the wicket gates.

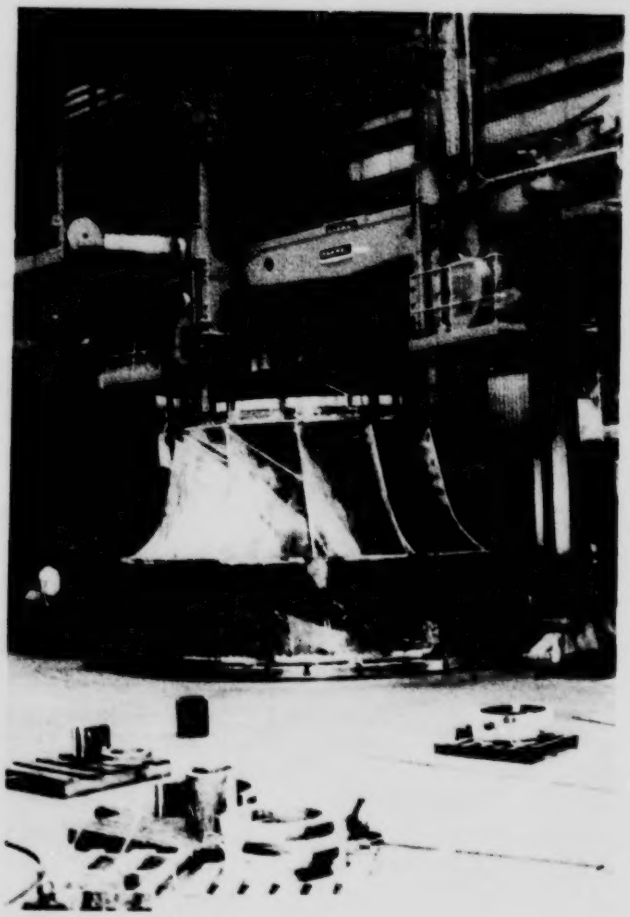


Figure 8 -

Machining of runner in one of Voith's York facilities Vertical Boring Mills.

2	4.5 TN capacity lift trucks to handle and transport wicket gates.
2	5 HP electrically operated variable speed, 150 mm x 5,200 mm L lineboring bar machining devices, to enlarge and align the head cover and bottom ring wicket gate bushing bores, in order to install new greaseless bushing cartridges. Figure 9 shows this bar at work.
1	20 HP in-house designed/built, electrically operated, variable speed machining column with two machining arms to machine the discharge ring curved lip and the wearing ring housings in both the discharge ring and the head cover.
1	Complete vacuum blasting equipment for blasting the water passage surfaces.

1	Ventilation system and 1 dehumidification system for the blasting and painting operation.
1	400 HP/13,000 C.F.M. mobile rotary screw air compressor for sandblasting.
1	Kwick-way cylinder boring machine to bore machine runner coupling bolt holes.
12	Vehicles for the field supervisory personnel.
2 sets	Generator rotor stands to minimize powerhouse space requirements.
(12 ea.)	Stands are high enough to allow stator re-wedging work while rotor is being stored.
2	Lamina precision hydraulic drills to redowell wicket gate stems to gate arm connections as wicket gates from different units are now installed.

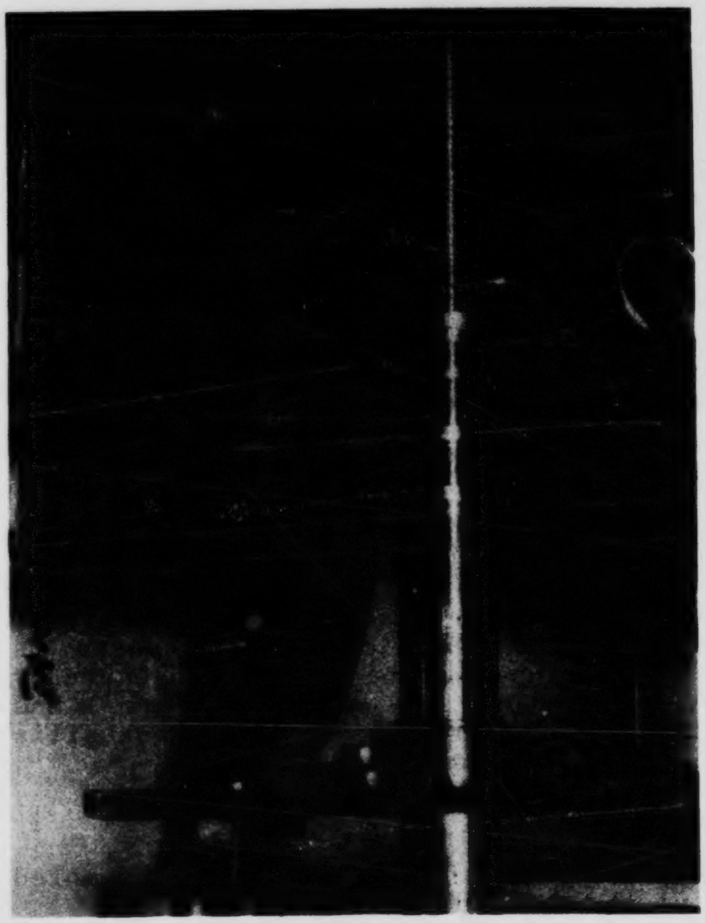


Figure 9 -

Field line boring

A team of 12 field supervisors directs and coordinates the work performed by the installation subcontractor. These supervisors are involved in all phases of field work including receipt of the shipment at the site, turbine erection, governor installation, wicket gate machining, coordination of all field work with the powerhouse operating persons, rewedging of the generator stators, machining of the discharge rings, Quality Assurance, Safety, etc.

Living facilities are provided by E.E.A. to house this group of supervisors and their families.

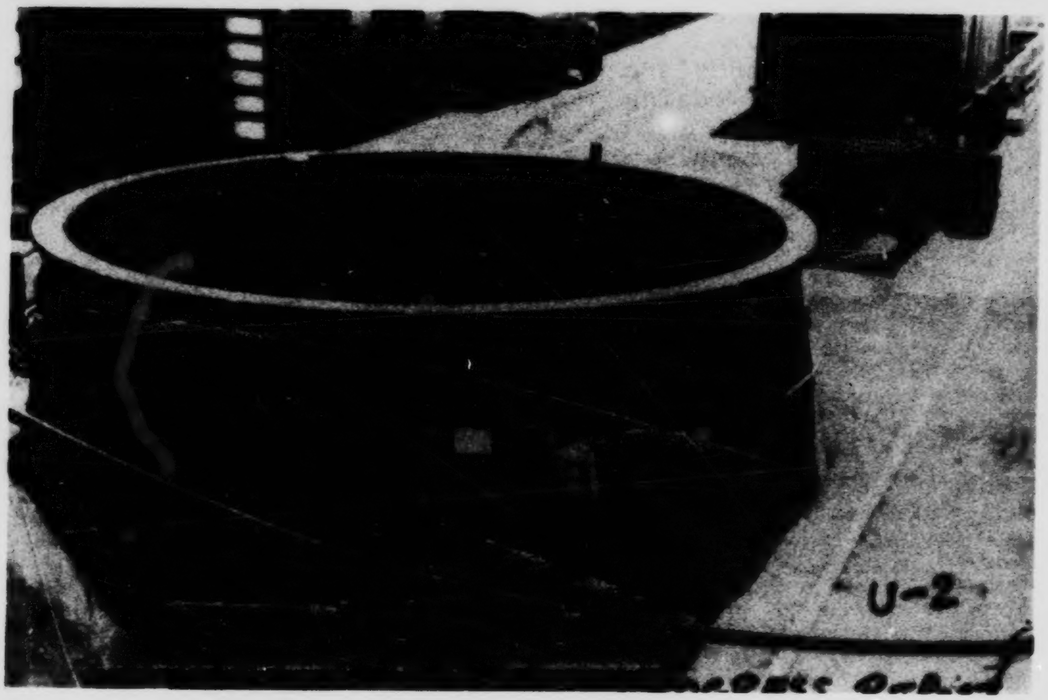


Figure 10 - New draft tube cone

DESCRIPTION OF THE FIELD WORK

Once authorization to commence the dismantling of a pair of units is received from EEA, the position of the parts is documented (i.e. flange elevation in the turbine/ generator connection, shaft runout, servomotors/gate mechanism, etc.) and then the units are completely dismantled. The main rehabilitation work is listed below:

DRAFT TUBE INSERT

This new draft tube cone, shown in figure 10, is assembled and welded in the bottom of the draft tube elbow, with the help of an erection platform to support it, built out of scaffolding tubes and strong planking. When ready, the cone is raised into location and hung from special supports previously anchored (see figure 11).

Welding of the insert to the wall of the original cone takes place when the insert is locked in its final position. After the circumferential weld is performed, the space between the original cone and the insert is grouted with a special non-shrinking grout. The grout holes in the top flange of the insert are then covered with welded plates. The "step" between the two cones is designed to support the full weight of the turbine rotating parts during erection.

MACHINING OF THE DISCHARGE RING AND THE HEAD COVER

As figure 12 shows in detail, large scale machining is performed to the discharge ring to accommodate a larger runner entrance diameter and to install a new stationary wearing ring. Also important is the machining of the head cover to place the new upper wearing ring support. Figure 13 shows a detail of this wearing ring configuration where machining takes place.

The whole machining operation takes from 3 to 4 weeks per unit with the work being performed in two shifts.

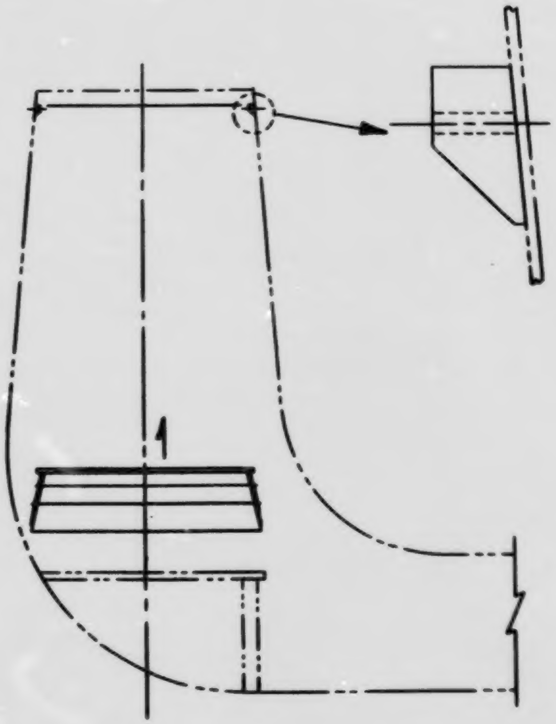


Figure 11 -

When ready, the cone is passed into location and hung from special supports previously anchored.

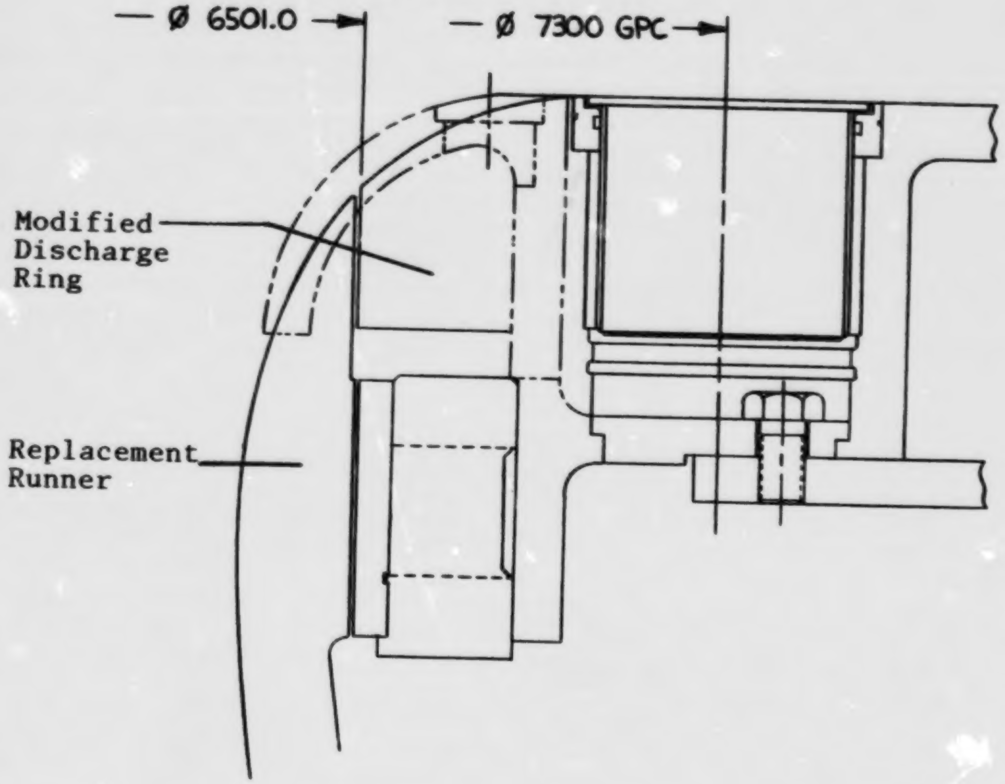


Figure 12 - Large scale machining of the discharge ring.

HEAD COVER/DISCHARGE RING LINE BORING

This operation is performed to increase the size of the wicket gate bushing bores at both the head cover and the discharge ring. The use of a boring bar assures perfect alignment of all bores. The final purpose of this work is to locate new bushing cartridges into these bores. These cartridges hold greaseless lubrite type teflon lined bushings installed by the use of a bushing chiller. This work takes around 2.5 weeks per unit, working in two shifts.

WICKET GATES REHABILITATION

All wicket gates removed from one pair of units are rehabilitated to be installed in the next pair of units.

The rehabilitation work consists mainly of machining the journals to shrink-in stainless steel sleeves for the new greaseless bushings. This machining is performed in a special lathe supplied specifically for this purpose.

Other than machining, NDT is performed in the area of the leaf to stem connection to detect possible cracks. Also, the leaf area is completely blasted and painted. The gate rehabilitation takes some 4 months to perform if no major repair is necessary.

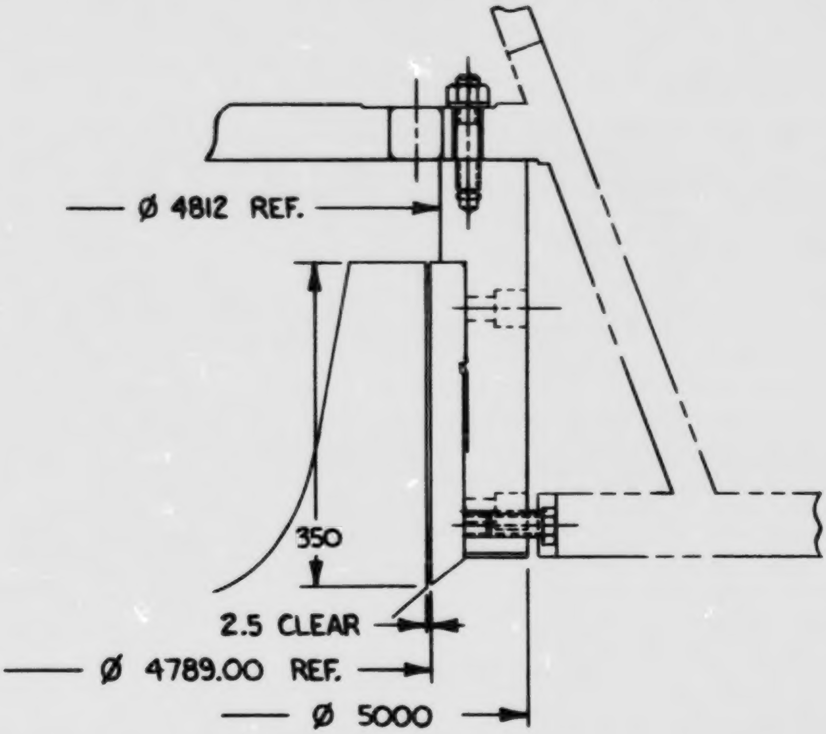


Figure 13 - Detail of machining of wearing ring support at the head cover

GENERAL REHABILITATION WORK AND COMPLETE PAINTING

All parts removed from the turbines are inspected thoroughly for damage or excessive wear. This applies to valves of any type, pumps, servomotors, turbine bearings, etc. All gaskets and seals removed are replaced with new sealant applied where necessary.

The generator parts are cleaned with special electrical solvent and the stator wedges replaced by newly designed ones. This work, which lasts two months per pair of generators, takes a full crew of people and a minimum of two winding specialists. After re-wedging is completed electrical insulating varnish is applied.

All of the turbine parts are completely cleaned and painted. The water passage surfaces are sandblasted and covered with coal tar epoxy.

All parts visible in the turbine pit are painted in colors specified by E.E.A.

EQUIPMENT GUARANTEE

All supplies and work involved in this project have been guaranteed for a period of 5 years starting at the time of recommissioning, except for the coating of the water passage surfaces and for the generator re-wedging works which are guaranteed for 2 years.

PROGRESS OF THE WORK

In May of 1986, rehabilitation of the first pair of units was completed, and the units returned to operation. The second pair was similarly completed in August of 1987, and work started on the third pair in December of 1987.

The operation of the first pair of units can be judged as very satisfactory during the first 17 months following unit recommissioning.

CONDITIONS OF OPERATION

Although the runners were designed for a range of heads between 50 and 74 M, due to the low flow condition of the Nile which resulted from the African drought of the past several years, the first two pairs of units have operated at heads substantially lower than 50 M, sometimes even lower than 45 M.

A runner cavitation and crack inspection took place in the first pair of units after 17 months of operation with no traces of either detected, thus confirming the high degree of refinement and accuracy of the design which predicted no occurence of cracks and guaranteed operation substantially free of cavitation for operation within the guaranteed range of heads. The runner crack inspection consisted of ultrasonic testing (U/T) and magnetic particle testing (M/T) of all bucket to crown and band fillet welds as well as 100% dye penetrant (P/T) testing of all bucket surfaces.

The results of this inspection confirmed the excellent performance of these turbines even though the operating heads had been well below the guarantee range. If the Nile flow condition continues to decrease, it is expected that the units may be required to operate at even lower heads. Additional model testing will have to be performed to verify that no problems would be encountered if operation under heads as low as 35 meters becomes necessary.

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Floating Bulkhead Installed for Hydro Intake Repair

By
J. Bakken, J. Vonasek

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FLOATING BULKHEAD INSTALLED FOR HYDRO INTAKE REPAIR

By James R. Bakken[1] and John S. Vonasek[2]

Introduction

Northern States Power Company (NSP) is an investor owned utility located in the midwestern United States of America. NSP-Wisconsin owns and operates several hydro plants in the State of Wisconsin. One of these plants, the Lake Wissota hydro plant, has been on line since 1917. After nearly 70 years of exposure to the elements, the powerhouse was due for major repairs. A floating steel bulkhead wall was designed, fabricated and installed to allow construction crews to make repairs.

Description of the Hydro Plant

The Wissota Hydro project is located on the Chippewa River about 3 miles upstream from the City of Chippewa Falls, Wisconsin, U.S.A. In upstream order, it is the third of six hydro projects on the main stem of the Chippewa River, all of which are owned and/or operated by Northern States Power Company. The Wissota reservoir, which is known as Lake Wissota, has a normal full water level elevation of 897.1 feet (273.4 m), National Geodetic Vertical Datum (NGVD) which provides a 57 foot (17.4 m) head. The reservoir extends upstream about 14 miles (22.5 km) and has a surface area of about 6,300 acres (2550 ha) with a normal full reservoir volume of 56,000 acre-feet (6.9×10^7 m^3). The drainage area upstream from the Wissota Hydro dam is 5,548 square miles (1.4×10^4 sq km). The hydro facility was completed in 1917. Figure 1 shows the project location.

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Structural components of the hydro facility include a gated spillway section with 13 Stauwerke automatic steel gates, a powerhouse with integral intake, and hollow non-overflow concrete dams on each end of the powerhouse. There is a 3,500-foot-long (1067 m) earth embankment on the right end of the gated spillway, which extends to the north abutment, a 1,000-foot-long (305 m) embankment between the spillway and the right concrete hollow dam, and a short embankment at the end of the left concrete hollow dam. The embankments have concrete core walls and the structures are founded on bedrock. A public road southeast of the dam serves as an embankment to contain the reservoir during high levels. Total length of the dam and powerhouse is about 7,800 feet (2377 m). The general plan of the development is shown on Figure 2.

The maximum height of the dam is 68 feet (20.7 m) above the streambed. The powerhouse contains six identical vertical shaft generating units, each with a generator name plate rating of 6,000 KW, for a combined generator name plate rating of 36,000 KW. Each of the hydro plant's six intake bays has a 26-foot-wide (7.9 m) by 24.5-foot-high (7.5 m) tainter gate located upstream of the turbine in each bay. These gates are closed in the event of mechanical failure of the turbine or wicket gates, and to allow for maintenance and repair of the units. Upstream of the tainter gates, vertical triangular trusses (Figure 3) support the trash racks and stoplogs. Four columns of stoplogs can be installed in each bay, supported on the ends in concrete slots formed in the concrete piers and by three steel trusses at intermediate points in each bay.

Alternative Dewatering Schemes Considered

After nearly seventy years of service, the intake area was due for major repairs. Repair on intakes began during the winter of 1986. Due to the deterioration of the trusses supporting the stoplogs, the strength of the trusses was not adequate to support the full head, so the annual spring drawdown of the reservoir was completed two months earlier and three feet (0.9 m) lower than normal to facilitate the repairs. Stoplogs were installed in the existing slots to dewater the trash rack and gate areas so that both deteriorated steel and concrete could be repaired. Once the intakes were dewatered, it became evident that the stoplog support trusses were more severely deteriorated than the initial underwater inspection indicated. One tainter gate was fully repaired and trash racks and much of the deteriorated concrete were partially repaired. The upper members of the stoplog support trusses were replaced; however, due to the remaining head supported by the lower part of the trusswork, all of the truss members could not be repaired. The severely deteriorated stoplog slots limited the amount of time for repairs to a short interval during spring drawdown and, because of remaining deterioration below the level of the drawdown, the stoplogs could not support the full head in the pond. It was decided at this point to take a new approach to repairing the intakes which would allow total replacement of the stoplog supports.

Repairing of the full height of the stoplog support trusses and slots required dewatering the intakes, one or several at a time. Loss of generation revenue due to the drawdown would be substantial. Drawing down the 6,300 acre reservoir to the required repair depth would also severely damage aquatic life, inconvenience shoreline residents and commercial establishments, and deplete groundwater levels below the depth of many shallow wells in the area. Because of these drawbacks, a deep drawdown was not practical.

A second alternative was to build a temporary cofferdam upstream from the powerhouse intakes. Such a structure would have been constructed as a double wall or cellular sheet pile structure filled with granular fill. A 65-foot-high (19.8 m) cofferdam would have been required to safely dewater the powerhouse area. The cofferdam would have been constructed in two phases to allow for continuous power generation. The high/excessive cost of this alternative prohibited its implementation.

A third alternative was to install a temporary steel bulkhead wall at the intake to each of the six bays. Cost of the bulkheads, in addition to barge and crane rental (the powerhouse is not accessible from land by heavy machinery), was excessive in relationship to the scope of the intended repairs.

NSP personnel suggested using traditional floating steel bulkheads, floated to the intakes and sunk in such a manner as to seal off the intakes. This would eliminate the requirement for having a barge mounted crane at the site, substantially reducing costs. Barely into the design phase, a member of the design team conceived the idea for hinging the individual floating bulkhead units together and sinking them as one articulated unit (Figure 4). The owner and designers all agreed the concept appeared promising, and, with much anticipation decided to proceed with the design of such a system.

Design

Four general requirements for design of the bulkhead were established at the onset of the project. First, each unit must float or sink, depending on the amount of water it contained.

Second, the units must be able to resist the hydrostatic pressures of the dewatering process. Third, upon removing the bulkhead, each unit must ascend slowly to reduce the potential danger of heavy units ascending quickly - rising above the water and damaging the dam, bulkhead or injuring workmen. Fourth, the wall must be comprised of units small enough to hoist out of the water and transport to other dams by truck.

Rolled rectangular tube sections were initially considered for the individual bulkhead units. This type of section was very desirable from a fabrication standpoint, as little cutting and welding would be required. However, such sections are quite heavy. Because of the limited depths available in rolled steel tubes, the anticipated deflections of the units at the bottom of the wall would be excessive, and could potentially cause problems with the bottom seal.

The steel section used for the wall is comprised of W27 x 84 beams in combination with 5/8-inch-thick (16 mm) steel plates. The beams have a very low weight to area (depth x flange width) ratio to achieve the required buoyancy. The selected material was readily available to many fabricators. Lighter sections were considered for the upper units since less strength is required under a lower hydrostatic head, but little economy would be realized in fabricating lighter upper units. Also, the wall would be less versatile and more complex with various size and weight units.

The introduction of hinges between each unit was initially intended for ease of placement. Other benefits were realized and some are listed below:

1. By allowing only selected compartments in alternate units to be filled, the bulkhead wall remains almost weightless in the water during placement and after the wall is fully installed (see figure 4). This provides easy maneuverability and requires hoists as small as two-ton (18 kN) capacity on each side of the wall. The weight of the steel sections used in the wall is approximately 68 tons (605 kN) dry weight.

2. Wall placement and removal can occur fairly quickly. Should the wall need to be installed or removed because of high runoff or emergency use in another location, only a few hours of preparation time is required. Also, diver time in the water is kept to a minimum - providing additional economy.

3. The placement process is safer, since little equipment is used and less work must actually be performed under water than with conventional bulkhead walls.

4. The wall may be used as a barge or work platform in the water, when it is not required for use as a vertical bulkhead wall.

The hinges were designed to allow 180° of movement and the pins are stressed only when the wall is being installed or removed. When the wall is either totally horizontal or vertical, the units are in direct contact with one another leaving the pins free to be removed or installed without shear forces on them.

Design and sizing of the bulkhead units were based on strength, deflections, and buoyancy. The bottom unit, after installation, was designed to span 30.9 feet (9.4 m) under a water head of 35 feet (10.7 m), which results in 2184 PSF (105kPa) pressure. The section, as shown in Figure 5, has about 15% additional bending capacity than required, according to the 8th edition of the A.I.S.C. Design Manual. The maximum calculated deflection of the section is 0.7 inches (1.8 cm). It was felt that deflections should be kept low, not necessarily to keep the total curvature low, but to keep the bottom seal from moving in the event of a significant change in the reservoir water level.

The design of the bulkhead buoyancy was based on a lower and upper limit. When "full" of water and descending, the bulkhead must be relatively light to allow a small hoist to set it in place. When "empty" and in the vertical position, the wall must be kept heavy to facilitate a slow ascent. This balancing act resulted in a limited amount of water to be used as the "sinking" force. The weights of the units, for varying conditions, are shown on Figure 5.

In addition to designing the bulkhead wall itself, assemblies of timber, steel and rubber were designed to act as a guide and seal for each pier nose. They consisted of wood, steel sections and rubber seals, all preassembled and anchored to the concrete piers with expansion anchors. The guides were necessary to ensure that the bottom units were in the correct location. In addition, steel pieces were placed at the bottom of the guides to pull the wall tight to the pier nose and provide a stop for the bulkhead wall when it reached its final position.

Three major locations requiring a seal were between the units, at the pier nose and at the base of the wall. Wood was placed against concrete because of its ability to conform to irregular, rough surfaces. Rubber seals were used at steel surfaces. Small leaks through and around the bulkheads were expected; however, the construction crews installing the bulkhead wall were experienced in sealing structures with cinders, rubber hose, etc.

The final major design concern was the durability of the newly fabricated structure. Special attention was given to the welds to assure that faying surfaces would not come in contact with water and corrode. All of the exterior surfaces were painted with a coal tar epoxy paint, and all interior surfaces were sprayed with linseed oil. The five compartments that are filled with water will get a re-application of linseed oil at regular intervals.

Fabrication

The floating bulkheads were scheduled to be fabricated within a five week period in order to install the bulkheads before the lake froze over, and to meet the schedule of NSP's construction crews. Cutting and welding proceeded around the clock at a local steel fabrication plant. The long, longitudinal welds required special care during welding to prevent warping the 36 foot (11 m) long bulkhead units. Many of the individual steel components had to be heat straightened prior to welding, in order to meet specified tolerance limits. Welding was performed by certified welders, and weld testing was provided by an independent testing laboratory as the units were completed. Pressure testing was accomplished prior to painting to ensure that the units were water tight.

While the bulkhead units were being fabricated, NSP construction crews were busy installing the steel, timber, and rubber pier nose pieces upon which the bulkheads were to bear and seal following installation.

Fabrication and delivery of the steel bulkheads was completed on time. NSP crews bolted rubber seals to the units prior to placing them into the reservoir from shore.

Scuba divers then pinned the bulkheads together at the hinges. Individual units were aligned by construction workers positioned on top of the floating units. Air temperature during the evening hours was below freezing, so crews removed sheet ice daily to keep a pathway open from shore to the powerhouse intakes.

Installation

On a cool January morning, construction crew members in a flat-bottom boat, powered by a 15 horsepower motor maneuvered the fully assembled 68 (605 kN)ton floating bulkhead into position at the hydro plant's bay 5 intake. Five-ton portable chain hoists were attached at each end of the bottom unit to provide complete control of the descent. Ports to the floodable bottom compartments were opened, and the bottom unit was filled with water from a garden hose. As the bottom unit was filled, it began to sink as the buoyant force became less than the weight of the steel unit.

The bottom bulkhead unit descended, pulling the other units behind it, with each floodable compartment filling on its own as it turned for its descent. Scuba divers periodically checked below water to ensure the bulkheads were properly aligned in the guides. The flexible, hinged bulkhead wall was lowered very much like a garage door closes. The buoyancy of the 136,000 pound structure ensured that only about 2,000 pounds actually rested upon the concrete below. Wicket gates at the turbines were opened and water pressure from the lake sealed the bulkheads against the piers and bottom. Divers used cinders and wooden wedges to seal minor leaks and make the installation nearly water tight. At this point, construction workers entered the dewatered intake area to begin repairs with the assurance of dependable dewatering facilities.

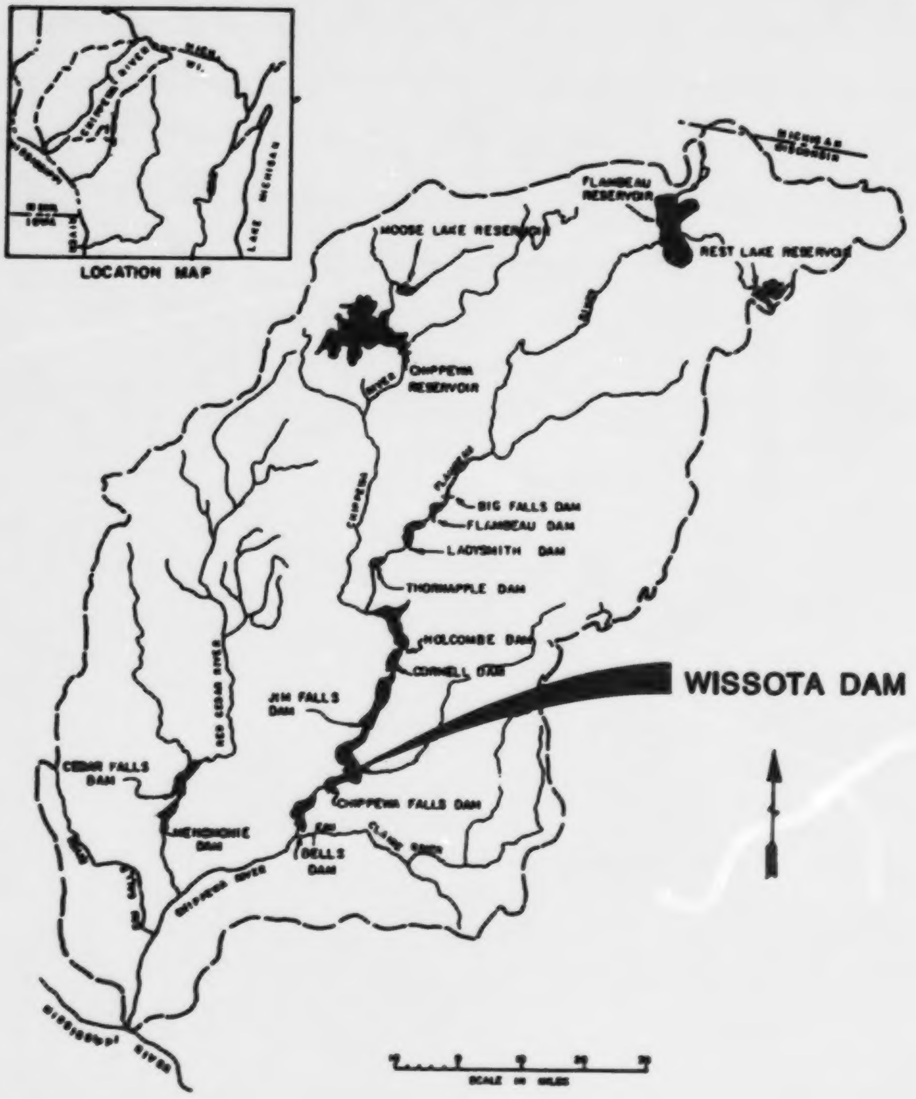
As the intake area was dewatered, the flooded compartments in the bulkheads drained and the filling ports were plugged. After construction crews completed repairs to the tainter gates, stoplog supports, trash racks and concrete, the intake area was flooded through two, 12-inch-diameter (0.3 m) ports in the bottom bulkhead unit. Equalizing the water levels on opposite sides of the bulkhead wall allowed it to float upward, much like one would open a garage door. Floating again, the unit was ready to install on another bay.

The first installation of the floating structure took four hours. Subsequent installations in other bays have taken as little as two hours.

Summary

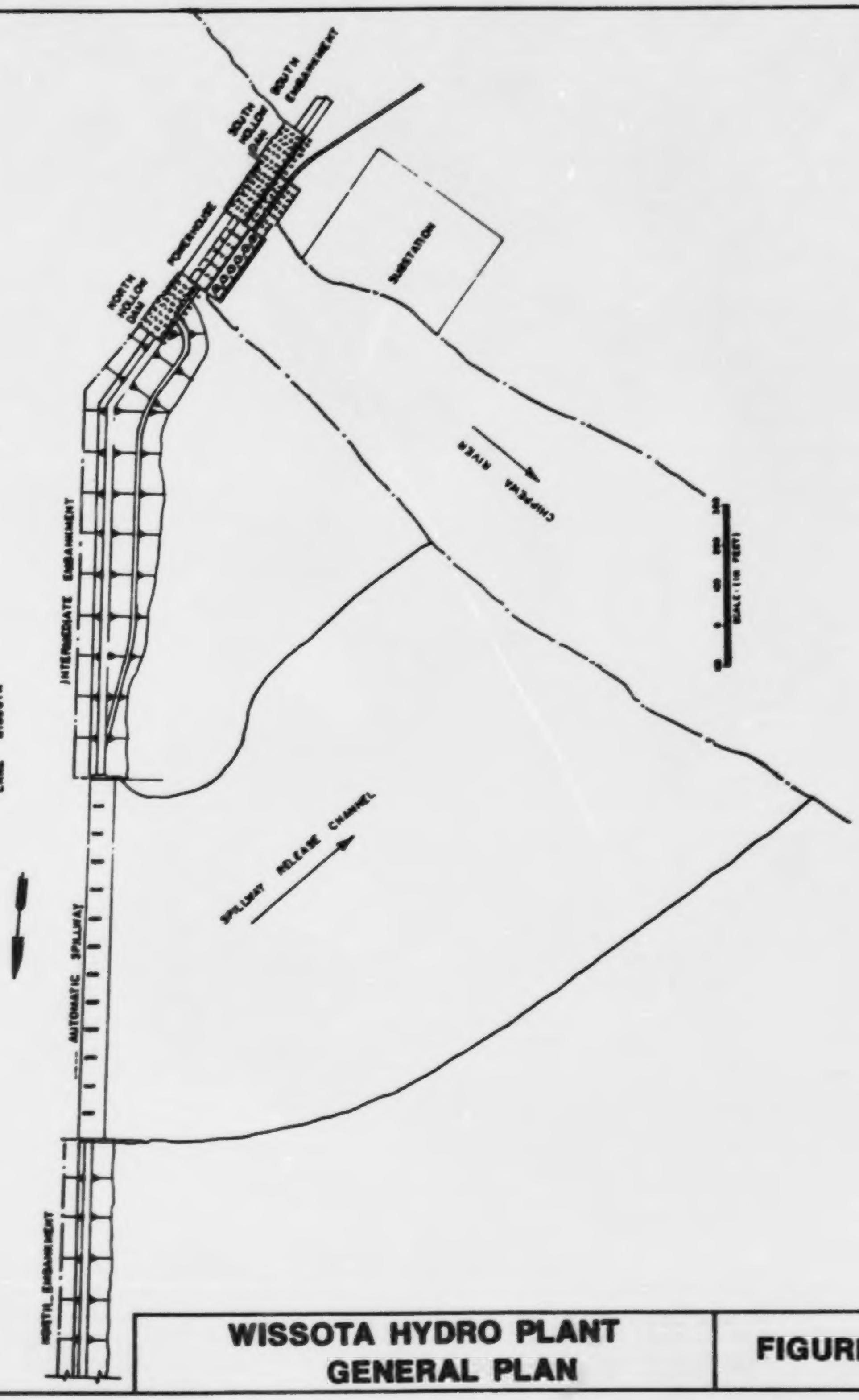
From initial discussions through the installation, this project was certainly a team effort. Open discussion and communication between each member of the design team, including NSP's representatives contributed to a successful project. Just ten weeks passed from the initial discussions to project installation.

The bulkhead is expected to be used for future repairs at many of NSP's hydro installations. To date, the floating bulkheads have only been installed at the Wissota hydro plant; however, the versatility and portability of the units when disassembled will allow transportation to other facilities by tractor trailer. Power company officials estimate a 1.4 million dollar savings through use of the bulkhead, including avoided loss of generation revenue because the drawdown or drawdowns were not needed. The bulkheads were fabricated for less than $130,000 (U.S.A. currency).


LOCATION MAP
MICH.
WI.
CHIPPEWA RIVER
MINN.
IOWA
LAKE MICHIGAN
MICHIGAN
WISCONSIN
FLAMBEAU RESERVOIR
REST LAKE RESERVOIR
MOOSE LAKE RESERVOIR
CHIPPEWA RESERVOIR
CHIPPEWA
FLAMBEAU
BIG FALLS DAM
FLAMBEAU DAM
LADYSMITH DAM
THORNAPPLE DAM
HOLCOMBE DAM
CORNELL DAM
JIM FALLS DAM
WISSOTA DAM
CHIPPEWA FALLS DAM
EAU CLAIRE RIVER
DELLS DAM
CEDAR FALLS DAM
RED CEDAR RIVER
MENOMONIE DAM
CHIPPEWA RIVER
MISSISSIPPI RIVER
SCALE IN MILES

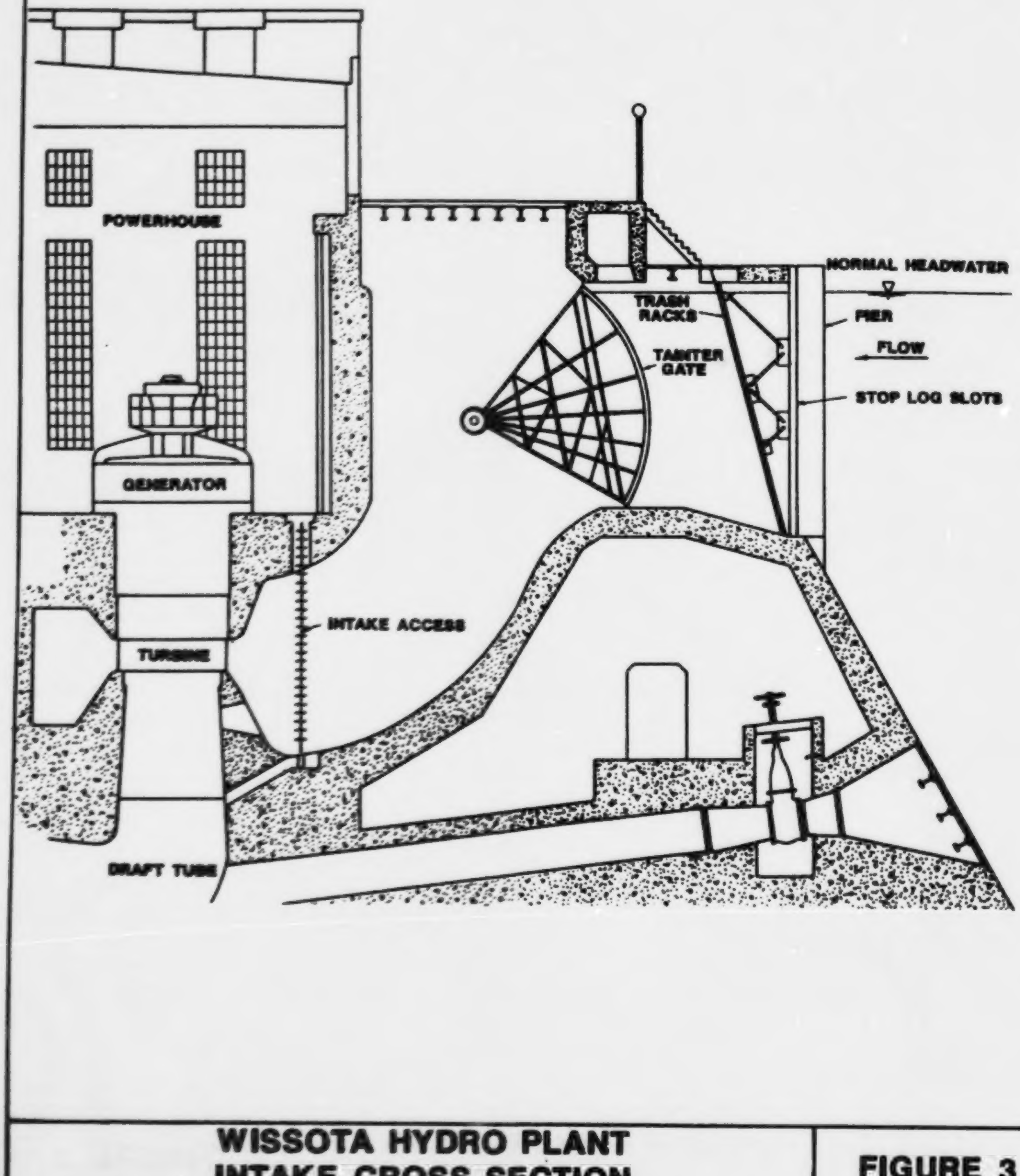
CHIPPEWA RIVER BASIN

FIGURE 1


SOUTH EMBANKMENT
SOUTH HOLLOW DAM
POWERHOUSE
NORTH HOLLOW DAM
SUBSTATION
CHIPPEWA RIVER
SCALE - (IN FEET)
0
INTERMEDIATE EMBANKMENT
LAKE WISSOTA
SPILLWAY RELEASE CHANNEL
AUTOMATIC SPILLWAY
NORTH EMBANKMENT

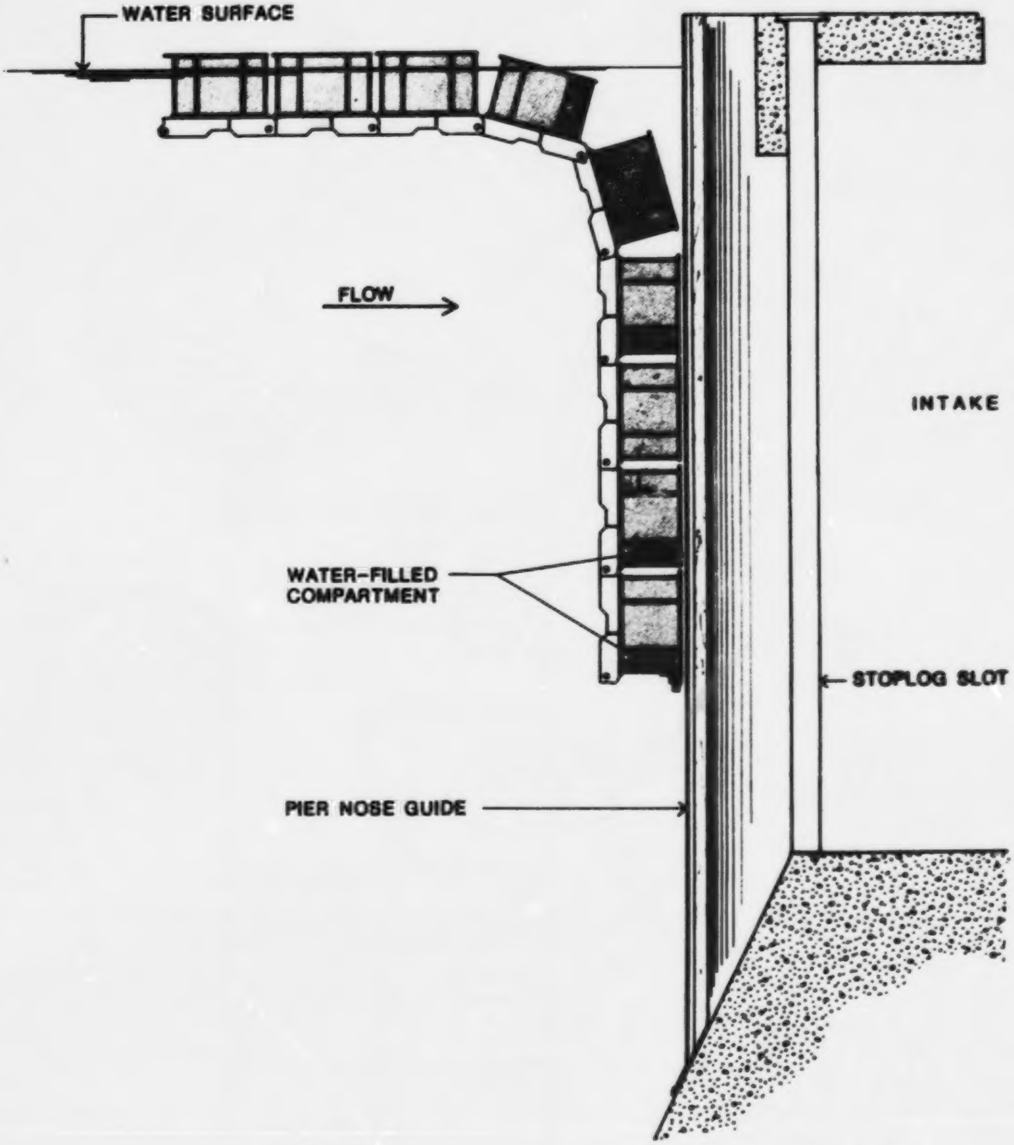
WISSOTA HYDRO PLANT
GENERAL PLAN

FIGURE 2


POWERHOUSE
GENERATOR
TURBINE
DRAFT TUBE
INTAKE ACCESS
TAINTER GATE
TRASH RACKS
NORMAL HEADWATER
PIER
FLOW
STOP LOG SLOTS

WISSOTA HYDRO PLANT
INTAKE CROSS SECTION

FIGURE 3

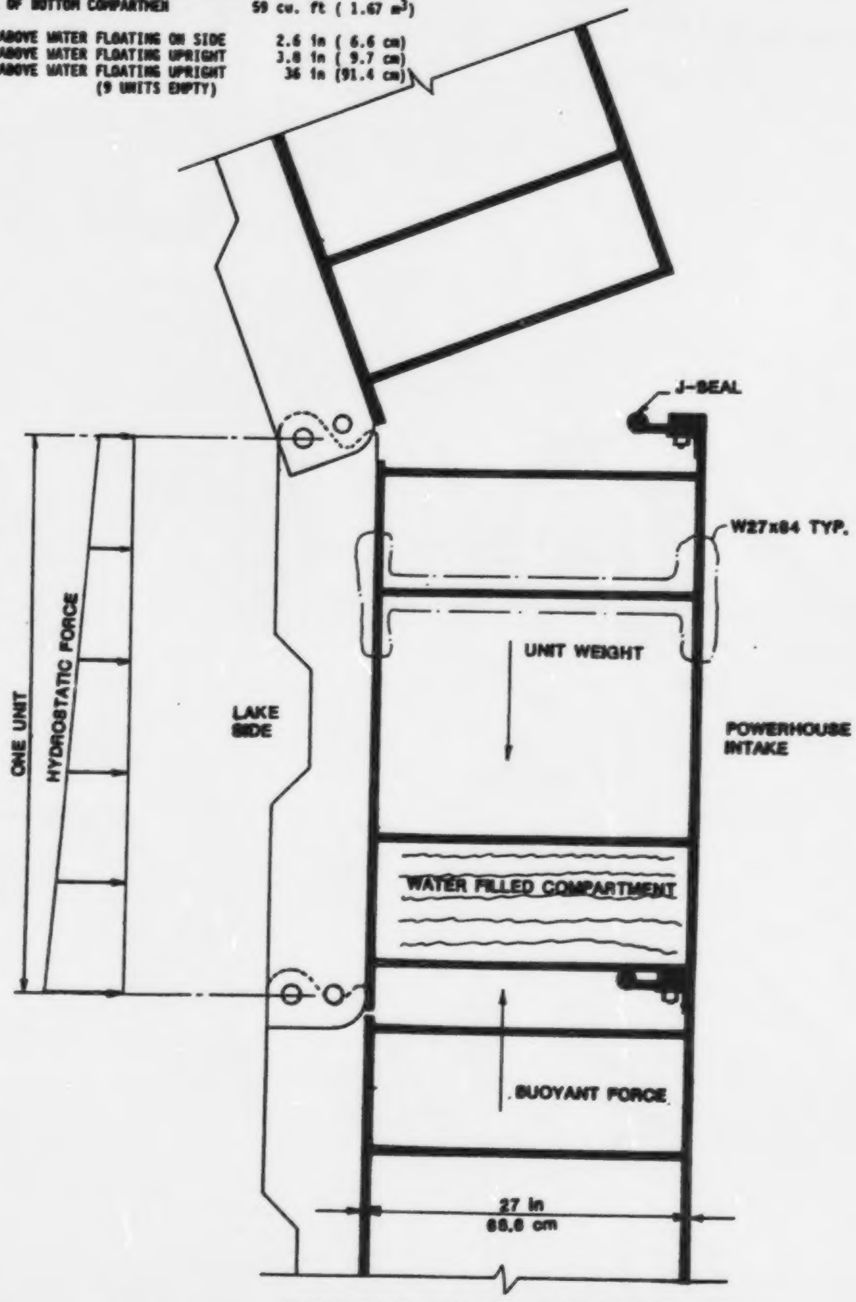

WATER SURFACE
FLOW
INTAKE
WATER-FILLED COMPARTMENT
STOPLOG SLOT
PIER NOSE GUIDE

SECTION THRU INTAKE DURING PLACEMENT OF FLOATING BULKHEAD

FIGURE 4

-BULKHEAD WALL DATA-

WEIGHT PER UNIT, EMPTY	15,200 lbs (67.6 kN)
WEIGHT PER UNIT, FULL	18,900 lbs (84.1 kN)
WEIGHT PER UNIT, EMPTY, SUBMERGED	-1,800 lbs (8.0 kN)
WEIGHT PER UNIT, FULL, SUBMERGED	2,000 lbs (8.9 kN)
% WATER IN BOTTOM COMPARTMENT TO SINK UNIT	47%
TOTAL VOLUME OF BOTTOM COMPARTMEN	59 cu. ft (1.67 m^3)
UNIT HEIGHT ABOVE WATER FLOATING ON SIDE	2.6 in (6.6 cm)
UNIT HEIGHT ABOVE WATER FLOATING UPRIGHT	3.8 in (9.7 cm)
WALL HEIGHT ABOVE WATER FLOATING UPRIGHT (9 UNITS EMPTY)	36 in (91.4 cm)


J-SEAL
W27x84 TYP.
UNIT WEIGHT
ONE UNIT
HYDROSTATIC FORCE
LAKE SIDE
POWERHOUSE INTAKE
WATER FILLED COMPARTMENT
BUOYANT FORCE
27 in
68.6 cm

SECTION THRU BULKHEAD WALL UNIT

SECTION THRU BULKHEAD WALL UNIT | **FIGURE 5**

SESSION 16:

CIVIL WORKS

Chairperson: B. Rinehart
Idaho National Engineering Lab.

Employment of Inflatable Weirs in Hydroelectric Systems

By
T. Muramatsu, R. Busch

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EMPLOYMENT OF INFLATABLE GATES IN HYDROELECTRIC SYSTEMS

Ted Muramatsu and Roger Busch

Introduction

Water diversion and storage systems have typically been made of such materials as concrete and steel. The inflatable gate is a new approach employing a reinforced rubber bladder. Fixed to a foundation, inflation raises the bladder to block the normal passage of water and deflation lowers it to the foundation to permit the free passage of water.

Inflatable gates were developed in the United States in the 1950's to replace flashboards which at the time were used for groundwater recharging. Although a promising idea, shortcomings in design and materials delayed widespread acceptance of the inflatable gate as an alternative to conventional water control systems until advances were made in the 1970's. There are today an estimated 1,300 inflatable gate systems throughout the world used in applications ranging from irrigation and recreation to groundwater recharging and tidal barriers. This new type of gate has recently been applied to hydroelectric systems as well.

Part I of this paper explains the inflatable gate and its operation. Characteristics of the inflatable gate relevant to hydroelectric systems are presented in Part II. The paper concludes with a description of two hydroelectric projects which employ inflatable gates in Part III.

Part I

The Inflatable Gate

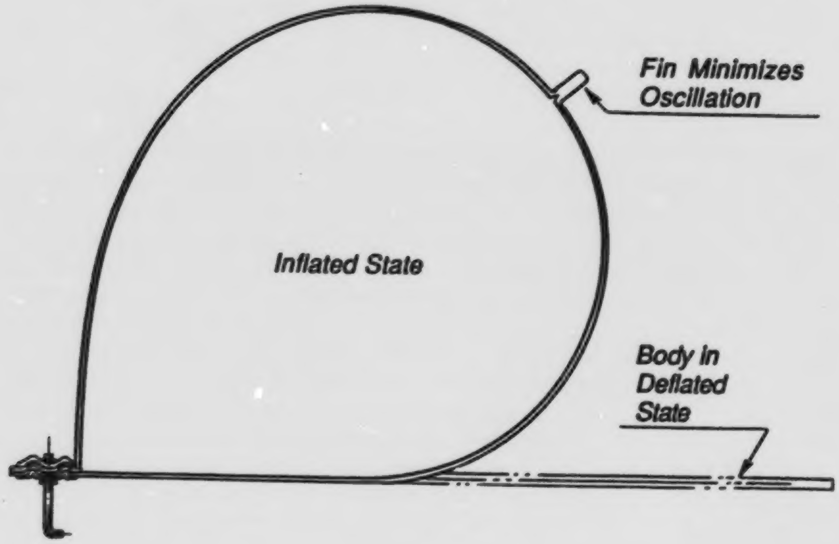
As unusual as it may seem, the inflatable gate is simple to understand. The rubber bladder which constitutes the gate stands upright when filled with air, forming a barrier to divert water or store it. This requires three basic systems: the inflatable gate itself, a method of securing it to the foundation, and a way of inflating and deflating it. Each of these three components will be described individually.

Those who first become aware of the inflatable gate are most curious about, and sometimes concerned with, its rubber body. Many have difficulty seeing a flexible material such as rubber doing the job of conventional materials such as rock, concrete, steel and wood which are normally applied to water control. However, it is the flexible nature of rubber which lends it the ability to absorb and dissipate stress. While the impact energy of rocks and debris on rigid materials is localized, the flexible, energy-absorbing nature of the rubber body of the inflatable gate disperses and dissipates it. The inflatable gate is a departure from conventional gate systems for it accommodates, rather than directly confronts, the immense weight and kinetic energy of water.

The energy-accommodating "organic" nature of the inflatable gate is of no benefit if its rubber body is not strong. While the design and materials of the bladder which make up an inflatable gate differ by manufacturer, one example of body construction is provided here. Tension in the inflatable gate body is born by nylon canvas, made air-tight by being encased in synthetic rubber. The rubber is compounded with EPDM (Ethylene Propylene Diene Monomer) for protection from heat and ozone. The total thickness of the body, depending on gate height and river conditions, is normally between 10.0mm to 16.5mm thick.

The rubber bladder which forms an inflatable gate must be both air-tight and secured to a foundation. The receiving part of the mounting system is composed of plates and anchor bolts embedded into the foundation at what will be the upstream edge of the gate. After holes along the upstream edge of the rubber body are placed over the anchor bolts, it is held in place by upper clamping plates secured with nuts. The clamping system performs two functions: it holds the rubber bag in place and creates an airtight seal between the two layers of the rubber body. The drawing on the next page shows a cross section of an inflatable gate and its method of clamping.

Cross Section of Typical Inflatable Gate



Like any gate, the inflatable gate needs a mechanism by which it is opened and closed. The system normally employed is composed of an air compressor connected via a pipeline to the rubber bladder. The gate is raised when filled with air; accomplished by opening the inflation valve and engaging the air compressor. Conversely, opening the deflation valve permits air to exhaust, thereby causing the gate to lay flat on its foundation in a fully opened position.

To ensure that they do not cause flooding in the event of a sudden surge in water flow, gates need a system by which they will open automatically. The system common to inflatable gates is mechanically operated, assuring operation even in the event of power loss. It employs a bucket or float in a chamber connected to the upstream water level which is, respectfully, either filled with water or pushed up by rising water. When the upstream water reaches a critical level, change in the tension on the cable holding the bucket or float causes an exhaust valve to open, thereby lowering the gate. An alternative system employes a simple blow-off pipe. This method relies on the increase in air pressure in the inflatable gate which results from a rising water level. When this air pressure reaches a set point, it expels water out of the blow-off pipe, permitting air in the gate body to escape.

While these automatic deflation systems are often used by themselves, many of the inflatable gates used in hydroelectric systems employ more advanced control systems with sensors which monitor the upstream water level and the inner pressure of the gate. Using this information, a microprocessor can maintain a steady flow of water through a penstock by executing small changes in the inner pressure of the bladder. The system also assures that any inadvertent leak in an inflatable gate will be meet with a compensatory input of air.

The time needed for a gate to open, or fully deflate, can be a critical safety concern in areas prone to sudden water flow surges. Deflation time is a function of the diameter of the inflation-deflation pipe and water pressure acting against the rubber body. Once the exhaust valve is opened a typical gate of about two meters high by 30 or 40 meters long will fully deflate and lay flat on its foundation within thirty minutes. Inflatable gate control systems for areas which experience flash flooding can be designed to automatically open in less time. As an historical note, the reason for the initial development of the inflatable gate in California was to provide an alternative to flashboards used for groundwater recharging which were often washed out when they could not be removed in time during sudden water runoff.

Part II
Attributes of the Inflatable Gate

Functionally, the inflatable gate fits in the category of water control devices which can be opened and closed. Small hydroelectric systems located at the bottom of ravines or valleys normally require gates in place of fixed water storage or diversion structures to prevent flooding common to such areas.

The following attributes of the inflatable gate result from its basic nature as described in Part I. These attributes make the inflatable gate different from conventional gate systems not only because of the unique material from which it is made but the design differences it permits.

A. Intermediate Piers: The inflatable gate permits long spans and few intermediate piers as its clamping system secures it along the entire length of the foundation, thereby distributing stress throughout the gate rather than at select points.

B. Side Slopes: The inflatable gate does not require 90 degree sidewalls, permitting it to accept the natural bank slope of a watercourse.

C. Maintenance: Painting is unnecessary and maintenance low as rubber is a non-corrosive material and the inflatable gate has no underwater mechanical systems. High operability makes inflatable gates suitable for hydroelectric systems which suffer financial loss when gate maintenance reduces electric production.

D. Flood Prevention: The automatic deflation system common to inflatable gates provides for reliable flood prevention.

E. Sediment Flush: Sediment flush is efficient due to the manner in which a deflated gate lays flat on its foundation.

F. Ice: Freezing temperatures cannot jam an inflatable gate in its raised position. The flexible nature of the inflatable gate also permits it to give (depress) when ice creates pressure against it, thereby permitting ice to pass over the rubber body.

The unique attributes of the inflatable gate establish it as a new option in the design of water diversion and storage systems. Part III of this paper presents three hydroelectric systems, ranging from mini to large, which employ inflatable gates.

Part III
Applications of Inflatable Gates to Hydroelectric Projects

Hatsuka River - Mini Hydro

The Hatsuka River inflatable gate is the smallest in the world applied to hydroelectric production. Located in a mountainous area in Hyogo Prefecture, Japan, its 1.4 meters (4'5") high by 8.0 meters (26'3") long inflatable gate diverts water to a turbine producing 450KW. Excess water overtops the gate.

The Hatsuka River inflatable gate is operated from a central control facility two kilometers away from the site. While the gate is normally opened by remote control on advance warning of heavy rains, the automatic deflation system has been engaged at times to prevent wash-out and flooding. This system employs a simple blow-off pipe. When a rising river water level increases the air pressure in the gate's rubber body, water in the U-shaped blow-off pipe is expelled, clearing it and permitting air in the gate to escape. This method of automatic deflation was employed as the standard bucket and float type systems were not practical given the remote placement of the control house away from the gate.

To be economically feasible, mini-scale hydroelectric systems must be simple in design and installation, remotely operated and virtually maintenance-free. The success of the Hatsuka River installation in these respects is leading to the extraction of electrical power out of heretofore untapped areas.

Hakone - Small Hydro & Replacement of Steel Gate

The run-of-river Hakone hydroelectric system in a mountainous resort area west of Tokyo generates an average output of 1.5MW. Water is diverted by a 1.8 meters (5'11") high by 14.0 meters (45'11") long inflatable gate retrofitted into an existing foundation which previously held a drum gate. Repeated damage to the steel gate, and concern that it might not rise during floods, led to conversion to an inflatable gate. When deflated during typhoons, the gate lays flat on its foundation under up to four meters of water surging down the 1/60 (1.7%) river gradient, permitting trees to pass and boulders to roll over it. To protect the concrete foundation itself against boulders, additional "apron rubber" was placed on the concrete foundation to protect it from cracking. The use of such energy absorbing armor illustrates the applicability of rubber in severe water environments.

The large number of inhabitants in the valley downstream of the Hakone gate makes fail-safe flood prevention an overwhelming concern in gate design. The challenge posed by such installations in upper mountain areas is that remote control operation, sharp river grades and sudden water surges make any gate system a potential hazard to downstream areas. The automatic opening function of the inflatable gate assures that it will open and maximize passage of flood water while its flexible, energy-absorbing nature permits it to harmlessly dissipate the energy of waterborne debris.

With over one thousand installations, there are more inflatable gates employed in Japan than in any other country. While most provide water for wet field rice cultivation, attention is now being directed to small-scale hydroelectric production in upper mountain areas, as in the two examples above.

The inflatable gate has been applied to a variety of hydroelectric systems, from mini to large scale and installed in the course of new system development as well as replacement or rehabilitation of existing facilities. It will be applied to a high dam as well when three spans are installed this summer on the crest of the 26.5 meters high (87') PG&E Pit 3 dam supporting an 89.1 MW plant. Proven in a wide variety of applications and environments throughout the world, the inflatable gate is moving from novelty to alternative.

Plastic Conduits for Small Hydro

By
E. Ausman, S. Thompson

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PLASTIC CONDUITS FOR SMALL HYDRO

Earle Ausman, PE Alaska

ABSTRACT

Case studies are presented on four small hydroplants using plastic conduits in Alaska. The small plants utilize PVC and PE pipe and have certain construction and operational defects. The plants are as follows: (1) Ouzinkie which has 18 and 21 inch PVC pipe; (2) Chitina a syphon pipeline of 21 inch PVC; (3) Rainbow Creek with 6 inch PE pipe; and (4) Burnett River power and water supply which is a syphon pipeline with 12 and 16 inch PE pipe. Included with these studies are the results of a field test on the resistance of PVC pipe to rifle bullets at reduced temperatures.

INTRODUCTION

Small hydropower plants in Alaska are generally in remote locations where logistics are complex and transportation is by water or air. Supplies and heavy equipment are not readily available and therefore expensive. In addition since the size of many small hydroplants is small, large expenditures for local roads and trails would result in unacceptable economics. Economics are driven by the low cost of fairly efficient, mass produced small diesel plants and the fact that almost every community is served for heating reasons by some form of oil delivery system.

In the past when the oil infrastructure and inexpensive engine generators were not available, small hydro was the choice. One of the largest expenditures which included freight and construction cost was the pipeline. The pipelines were generally built out of riveted steel or in some cases wire or rod banded wood staves.

Now, as in the past, the largest expenditure for most small plants is the pipeline although there are new choices which include steel pipe, and plastic pipe. The steel pipe now comes with rubber "O" ring gaskets which eliminates field welding to a great extent. In addition wrappings and coatings are more sophisticated and able to withstand corrosion which results in the loss of strength and an increase in hydraulic losses.

Intruding into steel's traditional domains are plastic pipes. The plastic pipe most prevalently used in Alaska for small hydro is made of high molecular weight polyethylene, PE. Another type of pipe material being used is polyvinyl chloride, PVC. To date PE pipe has been extensively used for hatcheries, many of which are subsidized by the Federal and State Governments. Many of these hatcheries in addition to using the pipe as a water supply use the head to provide power to the facility. In addition PE pipe has been used in a few small hydroplants. PVC pipe has been use in some micro hydro plants but the first significant use of it was at Chitina, then at Ouzinkie and in the future at the Larsen Bay project.

Plastic pipe is very attractive to project designers and builders in Alaska because it is frequently lower in cost, is light and easily handled and in the case of PE is easy to lay on top of the ground without anchors. The handling characteristics are of great importance because most remote sites or small villages do not have, nor can they readily obtain, heavy equipment such as large dozers, cranes, dump trucks, rock drills, air compressors and etc. To obtain such equipment would cost not only for the rental but for the high cost of ocean or air freight to the site. Local aggregates for concrete work such as anchors and thrust blocks are also difficult or impossible to obtain. For these reasons PE's ability to be winched over the surface and its low weight when used at low pressure is particularly attractive. PVC's major advantage lies in its price and ability to be installed without any specialized outside equipment, such as a butt fusion machine.

Other characteristics which are involved in the decision to select plastic pipe are the lack of a need to protect it against corrosion and the lower friction factors from such a smooth material. Some other less tangible benefits lie in plastics lower heat transfer rates and in PE's ability to withstand pipeline freeze-up without damage. Pipe made of a material such as PE does not require the degree of knowledge of local conditions and design nor as it is believed by some, care during construction.

Friction factors for plastic pipe as compared to steel, show that the more common plastic pipes are better. "C" values of PE and PVC range from 150 to 155; whereas, steel ranges from 140 to 145, depending on the coating, designer and so forth. Plastic pipe does not corrode. Even the best protected steel pipe will corrode. Further, with steel pipe it is difficult to be sure that a coating will survive where there has been no past experience, as is the case in remote Alaska.

Sunlight does not seem to have much effect on PE in Alaska but PVC must be painted or provided with an inhibiter. Steel of course is unaffected by sun but its anti corrosion coatings are.

Installation of PE pipe is easier in many locations because long sections can be dragged with a cable and a winch. PE pipe floats which aids in the installation of long under water intakes. PE pipe can accommodate many of the bends found in a small hydro line. However, if a bend must be sharper or some special connection must be made to the pipe, then special factory fittings are almost always required. PE pipe requires a heavy, expensive when rent and freight are considered, butt fusion machine.

Installation of PVC pipe generally must be installed underground; see result of rifle test. Provided ground conditions are amenable, IE not rock, then PVC pipe is a viable alternative. As a rule PVC pipe comes in shorter lengths which are easily handled, frequently by hand. Most communities have a small backhoe so digging is usually not a problem. PVC pipe is easy to put together because of the rubber "O" joint and can make modest bends. Bedding and padding of the trench will require more attention and cost due to PVC pipes more brittle characteristics. In addition depth of burial is more critical as the pipe is not continuous. Bedding and padding materials in a remote site not accessible by trucks and where screening plants and aggregate sources are not available can be prohibitively costly. However, because of low temperatures many of the pipelines built in Alaska require burial to protect them from freezing. Fittings can be fabricated for PVC pipe from fiberglass and polyester resin. In general this type of work is somewhat specialized and should be done indoors where temperatures can be controlled.

Cost comparisons of pipe materials are difficult to make in general but for heads up to about 150 feet, provided digging and backfill conditions are good, PVC pipe has a cost advantage. Comparing the cost of PVC and PE one finds that PE, with a price of about one dollar per pound and a design stress of 800 psi, as compared to PVC, with a price of about sixty cents per pound and a design stress of 2000 psi, results in a material price advantage of approximately 3 times for PVC. Steel suffers at reduced internal pressures because of minimum handling thickness and internal and external corrosion protection requirements which are a constant regardless of the wall thickness. At higher pressures and for larger diameters, steel pipe has the economic advantage over plastic pipe.

Larsen Bay

Design of the Larsen Bay plant, which is now under construction, illustrates the use of three different materials for the pipeline. This plant located on Kodiak Island will have 5,900 feet of main pipeline with a maximum head of 665 feet. This pipeline will connect to a impulse turbine which is capable of producing 450 Kw. The 3600 foot upper section of the pipeline is being bid as PE, PVC or steel although the original design and estimate was with 18 inch diameter PVC. The 2300 foot lower section of the line has been specified as 16 inch diameter, rubber "O" ring gasketed steel with the exception of the last 300 feet which will be bell and spigot welded joints to provide a virtual anchor. A diversion from an adjacent stream fork will require 4000 feet of 8 or 10 inch PE pipe with a SDR of 32.5. PVC was specified for the upper portion of the main line as it was less expensive, however; recent rapid increases in material prices may negate its advantage. As a result of rifle tests, a suspension bridge will be constructed of steel or PE pipe rather than PVC as in the original design. Steel pipe was specified for the lower section as plastic pipe was not obtainable in high enough pressure ratings (one supplier now states they can supply PE pipe in this range; however, the price is high). During the design effort a filament reinforced plastic pipe was considered but it is no longer obtainable. The surface laid PE pipe for the diversion will be dragged into place and may freeze. This pipe's gradient will be non uniform and it is not practical to drain water pockets. PE was the only possible choice in this situation.

Plastic mortar pipe to our knowledge has not been used in Alaska for small hydro. Although it has some advantages its price is high and it is heavy. Recently there have been failures of this type of pipe in Fairbanks, Alaska and a lawsuit is taking place. Fiberglass pipe is ideal for most alaskan sites but has always been too expensive although it appears to have become cost competitive in Europe. JM pipe made a PVC pipe with epoxy bonded fiberglass reinforcement that was available up to 12 inches in diameter. This pipe was reasonable in price, lightweight, had good friction values and would have been ideal for many small installations. Unfortunately for us in Alaska the pipe was not produced in larger diameters and the company has ceased production.

OUZINKIE

This small hydroplant is located in the community of Ouzinkie, near Kodiak, Alaska, provides power to the village. The plant has a net head of 231 feet, and uses 5200 feet of 21 and 18 inch diameter PVC pipe. The stream is diverted with a timber buttress dam. The pipeline was constructed in 1987 and the plant went on line June 6, 1988.

Installed for approximately half of the line was 21 inch pipe with a SDR of 51 which has a pressure rating of 80 psi, 1600 feet of the remainder was 18 inch pipe with a SDR of 41 and a pressure rating of 100 psi and the balance had a SDR of 32.5 and a pressure rating of 125 psi.

The pipe was built mostly within a access trail and was extensively travelled across by 4 wheelers and construction equipment which consisted of two large backhoes. It is reported that the upper material horizon was primarily some surficial soils and volcanic ash. It was clear from the surface that the underlying shales were also excavated. Based on verbal reports it is understood that there were no special provisions made for bedding and padding and that almost all of the work was done by the two backhoes not by hand labor. No special provisions were made for compaction of the ditch fill. Trench depth was reported to be from four to six feet.

It will be interesting to observe this pipeline over a period of time to see whether ovaling and lack of segregation of rocky materials cause leakage problems.

It can be said with some certainty that steel would not have been economical and its life would have been very problematical in this wet climate in volcanic ash.

CHITINA

A small hydroplant at Chitina, a village on the Copper River, is under construction. The plant will provide power to the community. The plant has 1900 feet of 21 inch diameter PVC pipe with a head of 100 feet. The system operates as a partial siphon from Trout Lake. Temperatures can drop below -50 degrees °F in this area.

In 1919 a small hydroplant was constructed on the banks of the Copper River. This plant, which supplied the railroad community of Chitina, had its water supplied from Trout Lake via a small diameter tunnel hence by wood stave pipe to the powerhouse. The original plan was to renovate the tunnel, but investigation disclosed that it had caved in. Because of the danger and the limited amount of money it was decided to construct a pipeline in a old railroad cut. The cut is now single lane road and parallels the tunnel. Even with ten feet of burial depth to protect the line from freezing the pipeline will become a siphon when the lake is drawn down. Although this siphon is only required to withstand a few psi it was decided to design the pipe to withstand full blockage at about 14 psi for short periods of time. A number of different types of pipe were considered. Work was to be done on a local force account basis and it had to take place within the center of the road. Another requirement was that the road had to be open for traffic each day. Therefor the joint system of the pipe had to be simple and easy to make and the lengths could not be too long. Investigations were made into the ability of "O" ring joints in PVC to withstand minor vacuum. Information from the manufacturer disclosed that they would. On this bases PVC pipe was the most practical and economical for the work.

The work started during the fall of 1986 with the blasting of a trench through the old railroad cut. Pipe laying commenced later in the fall than intended as the blaster did not show up on time and there were some high spots which had to be removed after his work. Construction within the cut proved very difficult as the trench had to be backfilled each day for traffic and the cut was so narrow that a backhoe could not turn around. The backhoe had to pile material between the tracks, back out and move material until sufficient distance was gained from the trench so the cat could operate. Production was between one to two 20 foot lengths per day in this section. The rubber gaskets for the pipe were kept warm within the cab of a pickup and taken out when the pipe was assembled. Bedding and padding were applied but compaction is uncertain as it is impossible to compact frozen gravel and sand. In spite of the -20 °F temperatures only one section of pipe was broken when the hoe hit it during reexcavation. One section of pipe was dropped at -20 °F off of a flat bed truck. The pipe landed on end and bounced several feet in the air from one end to the other without breaking.

Bends and bifurcation on this project were made up of PVC pipe sections which were fiberglass reinforced. The fiberglass work was done locally to increase the local labor content of the work to the maximum extent possible. Ashland Chemical kindly provided the procedures and resins to get a proper bond to the PVC. To aid in the bond the PVC was washed down with tetra hydro furan. The resin specified for the job had to have styrene and cobalt napthenate, a promoter, mixed in. This was required to extend the resin's shelf life and to enable the proper viscosity to be formulated. The local people report that the manufacture of the bends and the bifurcation is slow and they are unable to handle larger sections of roving or matt because of runs in the resin.

RAINBOW CREEK

This project is a run-of-river microhydro plant near Anchorage which supplies power to a home. The plant has 1200 feet of 6 inch diameter PE pipe with a net head of 150 feet. Several winters ago this pipeline, which is above ground, froze.

After the pipe froze, heat tape was fastened to the pipeline and two engine generator sets were run for over a week in an attempt to thaw out the pipeline. When success was not achieved, the plants were removed. After several weeks the temperature moderated and the line thawed on its own. Weather records disclose that the minimum temperatures could have been in the order of -10 °F.

It was the belief of some people that the plant froze up due to heavy icing at the tailrace pipe on this two jet impulse turbine, which reduced the flow of water. Regardless, when asked for a remedy the owners were instructed to put the pipe in a condition so that snow would cover the pipe all winter. Since dirt was not readily available the pipe was covered by sticks, twigs and needles which provided a platform for the snow to rest on. The result has been successful operation of the system over the last several winters.

An additional small hydroplant which is constructed with 4 inch PE pipe connected with mechanical joint connectors is located in Eagle River, north of Anchorage. This line is laid on the ground and has never frozen although the temperatures are probably a little colder in this location than Rainbow Creek.

This freezing of the pipeline illustrates PE's ability to withstand freezing without damage and the difficulty in applying enough heat to this pipe to thaw it out once frozen.

It may be of interest that the Rainbow Creek plant, which produces about 7Kw in the summer and about 5Kw during the winter when flows are down, is regulated by a Thompson & Howe electronic load governor which is made in Canada. The governor has proved excellent and very trouble free. The owners of the luxury home have learned to prioritize their use of electricity and base their decisions on a reduction in voltage signified by light dimming. The reason for the hydro plant so close to utility power was its cost was equal to a line extension constructed by the utilities union contractors to service the home.

BURNETT RIVER

This hydroplant and water supply pipeline, which is located on Etolin Island in Southeast Alaska, is comprised of approximately 4400 feet of 16 and 12 inch diameter PE pipe with a system head of approximately 184 feet is used in a fish hatchery. Prior to reaching the hatchery the water flows through a Cornell Pump which is connected to a synchronous generator. Like the Rainbow Creek plant the frequency is regulated by a Thompson & Howe electronic governor. This load governor, which replaced one with considerable problems, has proved trouble free.

The turbine produced a reported 37 Kw on initial operation after the pipe was filled and purged of air. After several months the power output dropped to 17 Kw. Somewhere near this point the pipe collapsed completely shutting off the water. Then the pipeline started again repeating the process.

Based on review of turbine output curves the system should be producing 40 Kw at 127 feet of net head. Hydraulic calculations showed however that the pipelines net head should be closer to 164 feet which would more closely correspond to the output of 80 kw that the unit is rated for. Since the turbine is subject to some backpressure while providing feed water to the hatchery and there are no pressure gages, with the exception of one on the scroll case, the owners were advised to put pressure gages on the outlet and the intake of the machine so the actual head would be known at minimum flow. This has not been done so the detailed analysis that was to be presented with this paper has not been accomplished.

The pipeline intake system in the lake is made up of two branches. The one to -55 foot of depth is comprised of 400 feet of 16 inch and 200 feet of 12 inch PE pipe. The second branch to take water from a shallow depth is comprised of 400 feet of 12 inch PE pipe. The pipe is weighted to hold it down. The land portion is comprised of 12 inch diameter SDR 19 and SDR 32.5 pipe which is laid on the muskeg and in some cases on cribs built of locally obtained sticks. The profile of the pipeline shows it rises several feet above the lake elevation then runs shallowly downhill for about 1400 feet. At this point the pitch steepens. The pipeline collapse occurred in this steeper section at a point about 1800 feet from the lake or 2400 feet from furthest pipeline intake. The lake elevation is at 221 feet and the flattened section at 192 feet elevation is in a section of pipe with a SDR of 32.5. Below this section the profile steepens again and in this area the sound of flowing water, indicating open channel flow, can be heard.

It is suspected that the pipeline was selected using charts which did not account for several important characteristics of PE pipe. One such characteristics is that there is about a 7% increase in friction from colder water found in Alaska. The second and most serious characteristic is that PE pipe has thick walls and selection of the pipe based on the nominal outside diameter will result in large errors.

Another area of concern is the selection of the pump which is run as a turbine. Because the pump at synchronous speed essentially acts as a orifice it is clear that a under designed pipeline will result in partial head on the pump to the point where the turbine discharge and pressure reduction balances the pipe net head. In a situation such as this care should be exercised so the turbine can not lower the net head on the pipe to a point where the turbine is no longer operating in its efficient range.

The installation of the pipe was accomplished by stockpiling with a helicopter and then butt fusing the pipe into 480 foot long sections which were equipped with flanges. These sections were then dragged into place with small chainsaw engine driven winches. When the pipe first collapsed one section of pipe, with half the joints made up of pipe with a SDR of 19, was moved up the hill and the second section with SDR 32.5 pipe was pulled down the hill. This did not solve the problem.

It has been recommended to the operator that taps be put into the pipe and a small portable gasoline pump be used to evacuate the gas which is given off when the water is decompressed. If this were done the plant would produce 37 Kw, as a minimum, and more water would be available for the fish.

PVC PIPE, RIFLE TEST

A section of the Larsen Bay pipe had to be elevated over a deep gully. To span the gully it seemed logical to use a suspension cable and PVC pipe. The question is what would happen if the pipe were shot.

To answer this question two bell ends of 12 inch diameter PVC pipe were capped and a 4 foot section of SDR 51, 80 psi pipe was inserted between them. The pipe was filled with water chilled with ice to about 33 degrees. The pipe surface was also chilled with a bag of ice. The pressure in the pipe was raised to 80 psi and the pipe was shot with a 22 long rifle at close range.

The bullet hit the chilled area and the pipe burst with cracking in a x shape with the right and left arms of the x tending about 20 to 25 degrees off of the center line. These cracks ran into the area of the "O" ringed gaskets. After the results of the test with basically a low energy bullet a similar test with a 338 magnum big game cartridge, which is typically used in the Kodiak area for bear protection, was not tried.

One of the left over sections of the pipe was shot while empty. The 22 bullet made a hole about the same size as the bullet diameter when it went in and made a large hole and the start of longitudinal cracks on the opposite side of the pipe. The 338 magnum went into the pipe with a hole smaller than the bullet and emerged with a hole about bullet size which was surrounded by a crater. There was no cracking around this hole.

CONCLUSIONS

Plastic pipe is and will be of considerable use in Alaska but even its forgiving nature can not overcome poor design and construction practices. It is expected that more and more small hydro conduits in Alaska will be made of plastic. It is hoped that manufactures develop low cost pipe for higher heads and flows.

Overflow Embankment Dams in SHP of China

By
W. Xianhuan

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OVERFLOW EMBANKMENT DAMS IN SHP OF CHINA

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Feb. 1988

OVERFLOW EMBANKMENT DAMS IN SHP OF CHINA

Wang Xianhuan*

Since 1950s, China began to study the overflow embankment dam. Lab tests were mainly focused on the structural detail of slope protection and hydraulic problems, including energy dissipation. First Beliashevski-type rockfill dam and overflow earth dam were built in late 1950s. So far, we have built more than 200 overflow embankment dams, of which about 30 are of earthfill type. Some of existing overflow earth dams have never been overflowed yet due to overestimation of run-off and most of them had more or less troubles after completion or operation.

The Jiaoshi dam in Jiangxi province was of earthfill type with concrete core, completed in 1959, and some troubles occurred after completion mainly due to differential settlement and poor-designed filters. Successive repairs and strengthening measures had been carried out until 1965. It was safely overflowed with a flood corresponding to a unit discharge of 17.2 m^2/s in 1971 and now works well (Fig. 1).

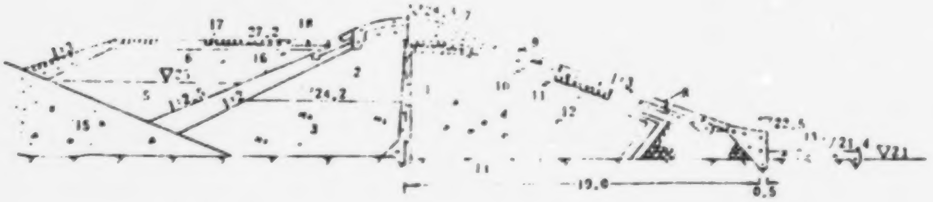

Fig.1. Jiaoshi overflow dam

In Fig.1, 1--concrete core; 2--sandy loam; 3--clay;
4--gravel; 5--silty sand;
6--claey loam filled by dumping-in-water method;
7--R.C.cap, 25 cm thick; 8--concrete slab, 25 cm thick;
9--concrete slab, 20 cm thick;
10--dry-laid masonry, 30 cm thick;
11--gravel, 15 cm thick; 12--coarse sand, 25 cm thick;
13--concrete apron; 14--rock foundation;
15--overburden; 16--original upstream face;
17--dry-laid stones; 18--concrete slab.

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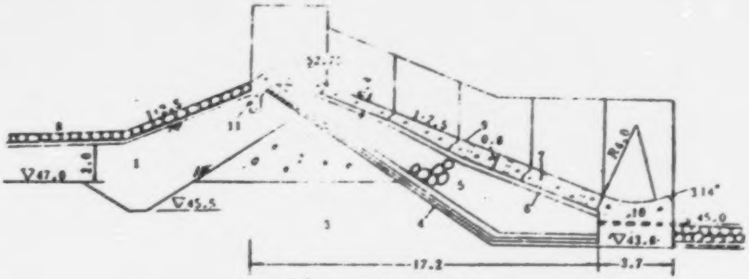
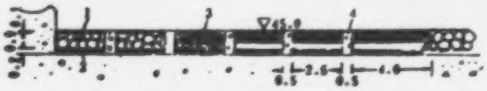
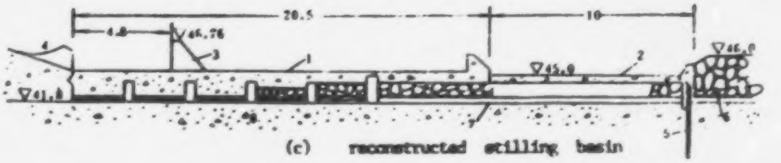
Fig.2 is the cross section of Hengpaitou dam in Anhui province, 9 m high, constructed on soft foundation. The original dissipator was of rolled bucket type with a low nose, and the downstream protected by bamboo gabions, as shown in Fig.2b. After several years of operation, bamboo gabions were eroded away due to decay of bamboo, thus leading to a bad hydraulic performance. In 1964, the original dissipator was rebuilt into a stilling basin (Fig.2c), which had safely passed a flood of 6,420 m^3/s corresponding to a unit discharge of 12.5 m^2/s.



(a) cross section



(b) original dissipator



(c) reconstructed stilling basin

Fig.2 Hengpaitou overflow earth dam

In Fig.2a, 1--sloping core; 2--sand-gravel fill;
3--sand; 4--filter; 5-dry masonry;
6--mortar masonry, 0.3 m thick; 7--drain;
8--hand-placed riprap; 9--concrete slab;
10--bucket; 11--asphaltic paper.
In Fig.2b, 1--dry-laid stones; 2--filter;
3--bamboo gabion; 4--concrete grid.
In Fig.2c, 1--concrete floor; 2--downstream apron;
3--baffle block; 4--chute block; 5--concrete pile;
6--riprap; 7--filter; 8--sand.

Fig.3 is the Hongxing dam in Hunan province (1), 20.2 m high, designed for a 20-year flood of 123 m^3/s and completed in May, 1977. After passing a flood in June the same year, 10 cracks of various sizes occurred on the downstream face due to differential settlement (Fig.4), and immediate repair measures were taken. Since then, the accumulated duration of overflowing has reached more than 10X10^3hrs, with a max. discharge of 61 m^3/s and a max. flip velocity of 9.1 m/s.

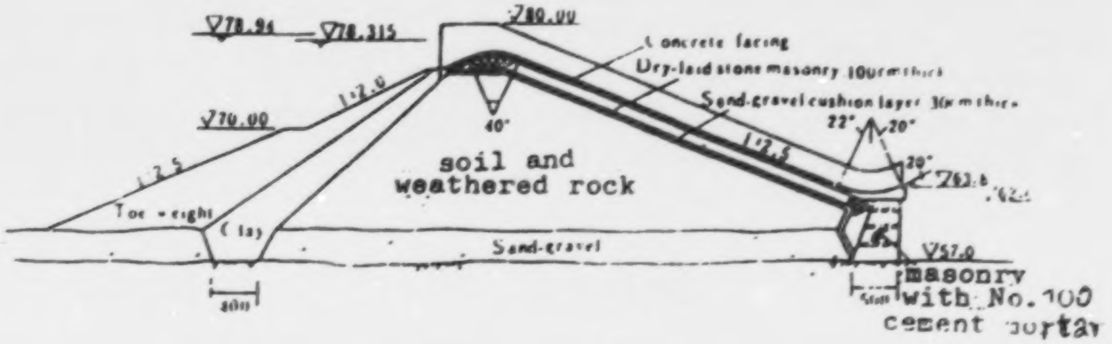

∇78.94
∇78.315
∇80.00
Concrete facing
Dry-laid stone masonry 100cm thick
Sand-gravel cushion layer 30cm thick
1:2.0
∇70.00
40°
22°
20°
20°
1:2.5
1:2.5
soil and weathered rock
∇63.6
Toe weight
Clay
Sand-gravel
∇57.0
400
500
masonry with No.100 cement mortar

Fig.3. Cross section of Hongxing dam

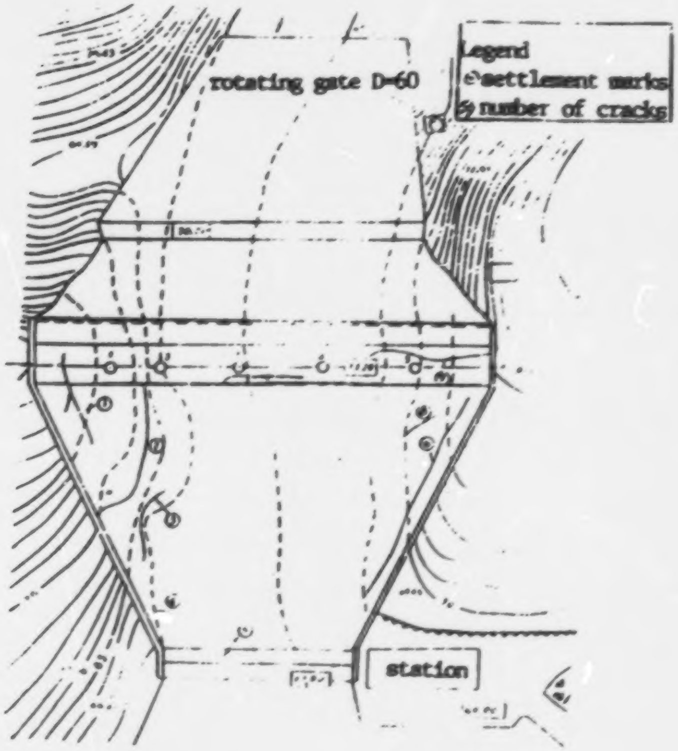

rotating gate D=60
Legend
settlement marks
number of cracks
station

Fig.4. Cracks on the spilling surface
(power conduit unshown)

As far as the overflow rockfill dam is concerned, it had far better performances than overflow earthfills. Here, some recommended types of overflow rockfill dams are introduced.*

1 Beliashevski-type Rockfill Dam

This type of overflow rockfills was first constructed in early 1950s in Ykraine, USSR, proposed by Prof.N.N. Beliashevski (2). They were mostly constructed on soft foundation, with high tailraces. This type of dam was introduced to China in mid-1950s, with good performances during operation.

Fig.5, 6 and 7 are three typical examples. The downstream face was laid with concrete slabs or cement-mortar stones, terminated with retaining blocks. Its excessive energy was generally dissipated by rolled bucket of low-nose type. The Saddle River dam is located in Liaoning province, China, 7m high, with a design discharge of 537 m^3/s, corresponding to a unit discharge of 10 m^2/s.

The overflow dam of Beliashevski-type is generally terminated with a supporting block, of which the stability should be well ensured under all external forces. Our practice shows that flip bucket (Fig.3) and stilling basin (Fig.2) can be also used in this type of overflow dams. During planning, great attention should be paid to : 1) the differential settlement of embankment and 2) the design of slope protection and its sub-base. As for the slope protection, two types are generally used, namely the pervious slab (including wedge-shaped slabs) and impervious slab, which have their own merits and demerits. But Chinese engineers inclined to the impervious type, due to its better hydraulic performances, such as dynamic and impulse pressure. Generally speaking, the uplift resulting from the seepage through the dam can be properly avoided. However, the leakage through creacks or joints in the upper portion would result in some uplift affecting the performance of downstream portion of the impervious slab. As a result, attention should be paid to the estimate of differential settlement and the design of the filtrating sub-base. And also, the slab had better be anchored to the embankment, with its sub-base being properly underdrained.

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* Filtrating rockfill dam and temporary overflow cofferdam or protected rockfill-gap for uncompleted rockfills have never been used as permanent structures in China and are not introduced here.

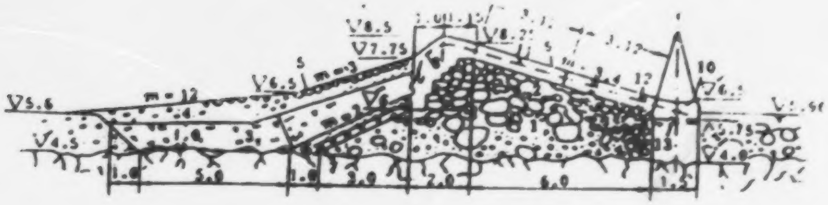

∇8.5
∇7.75
∇5.6
∇4.5
m=12
∇6.5
m=3
5
10
1.0
5.0
3.0
2.0
6.0
1.5

Fig.5. Bratzslavski dam

In Fig.5, 1--rockfill of the old dam; 2--added rockfill; 3--loess-type loam; 4--sand-gravel fill; 5--hand-placed riprap; 6 and 7--filter; 8--concrete cap; 9--slabs; 10--supporting wall; 11--reinforcing steel; 12-- 5-6 cm drains; 13--10X10 cm drains, 2m on centers.

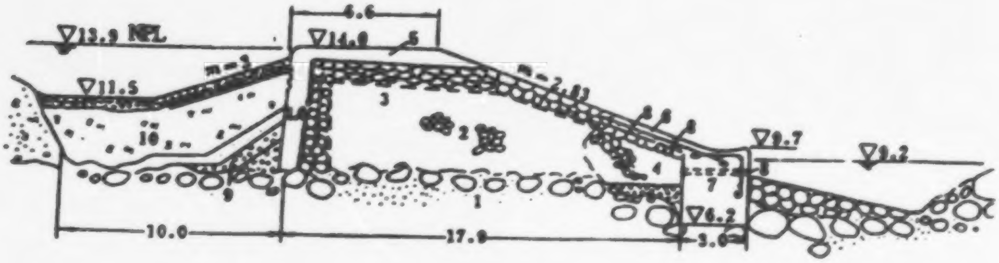

6.6
∇13.9 NPL
∇14.0
5
m=3
∇11.5
3
2
10
9
1
4
7
8
∇9.7
∇9.2
∇6.2
10.0
17.0
3.0

Fig.6 Sherbakov dam after reconstruction

In Fig.6, 1--alluvion with boulders; 2--old rockfill; 3--old mortar-laid surface; 4--added rockfill; 5--concrete cap; 6--concrete slabs 0.6m thick; 7--supporting wall; 8--drains; 9--filter; 10--claey loam.

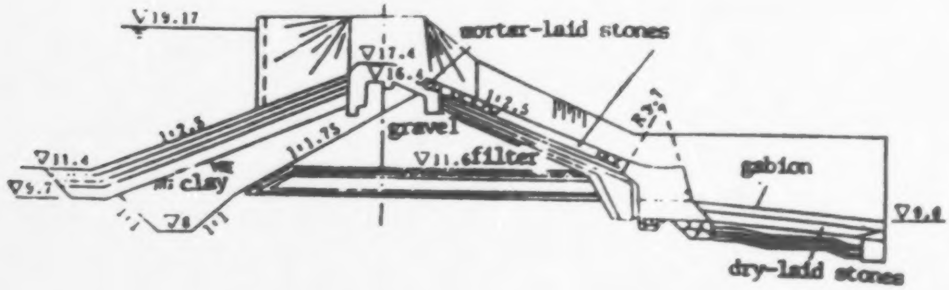
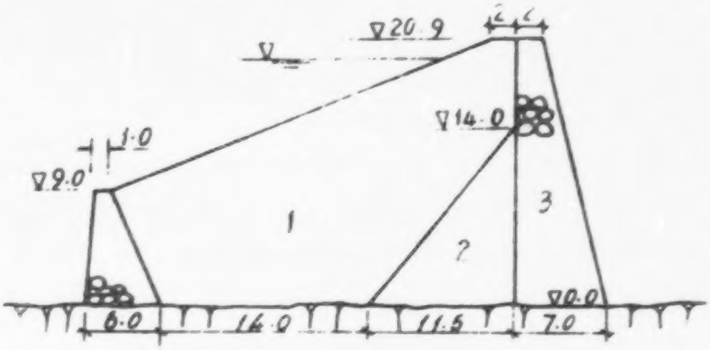

∇19.17
mortar-laid stones
∇17.4
∇16.4
1:2.5
gravel
1:3.75
∇11.4
∇9.7
clay
∇11.6 filter
gabion
dry-laid stones

Fig.7 Saddle River overflow dam

This type of overflow rockfills can be applied to a dam height of less than 8 m, with a unit discharge of 20-5 m^2/s, depending on the difference between headrace and tailrace.

II Chaoguche-type Rockfill Dam

The first dam of this type was innovated by the local technician and completed in 1959 at Wenling county, Zhejiang province. This dam (Fig.8) was designed of non-overflow type, and there was no filters to be used. Even though, after completion, it had been overflowed many a time, with unit discharges up to 2 m^2/s, and worked well. Afterwards, the bank spillway was extended to guarantee the dam being operated in non-overflow condition. This experience encouraged more designers to develop an overflow rockfill dam of this type. Practice showed that this overflow type of rockfill dam had following advantages:



In Fig.8,
1--clay;
2--rockfill;
3--dry-laid stones.

Fig.8. Longtankeng dam at Chaoguche

1) convenience for river diversion.
2) less amount of dam volume.
3) possessing a certain capability of overflowing and being suitable for small dams with small drainage areas.
4) availability of materials in mountainous or hilly regions.
5) availability of technical skill for the local people.

Shortly afterwards, this type of overflow dam was rapidly developed. Up to late 1970s, about one hundred of Chaoguche-type overflow dam were built in the province. As this type of dam originated at Chaoguche, it was named by the people so called "Chaoguche type". In late 1970s, the Zhejiang Provincial Hydraulic Research Centre (ZPHRC) summed up the experience and carried out hydraulic tests and analysis (3) on stability, hydraulic computation, etc. Fig.9 is the Laxia dam, a typical example in the province. Here, some design features are briefly introduced.

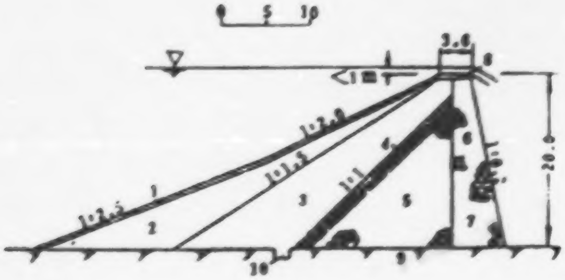


Fig.9. Laxia dam

In Fig.9,
1--dry-laid slope protection;
2--sandy loam;
3--clay; 4--filter;
5--rockfill;
6--dry-laid stones;
7--mortar masonry;
8--mortar-laid ashlar stones;
9--rock foundation;
10--trench.

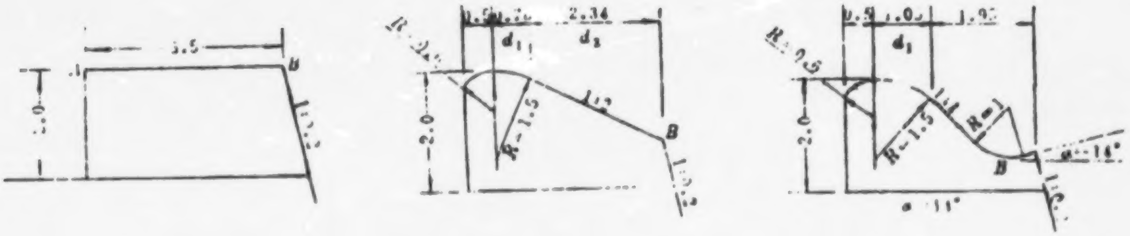
1. Supporting Wall

The supporting wall should resist the pressure from the rockfill, based on limit equilibrium principle or rigid section method. As a result, this wall should be located on the competent rock. To increase its capability against sliding, it can be arched in the plan, with an arch camber of 1/10 crest length. The wall is carefully laid with cement mortar, but special drains should be properly provided.

The top width of the wall is generally 2.5 - 3.5m, depending on the dam height. Its upstream slope had better be vertical, giving less influence on the settlement of the rockfill; the downstream slope is generally 1:0.1 - 1:0.2, avoiding the scouring by the jet near the dam toe and taking into consideration the jet impact on the wall during small discharges. According to our test, when the depth at crest is less than 0.5 m (for flat crest, shown hereinafter) or 0.25m (for other types of crest), the overflowing water would impact, or flow along the downstream face of the wall. In some cases, a properly-cantilevered crest is preferable.

2. Hydraulic Computation

ZPHRC had made model tests on the discharge capability and throw distance of various crest types, among which three types of crest shape are recommended (Fig.10) here.



a) Flat crest b) Round crest with free fall c) Round crest with bucket

Fig. 10 Recommended crest types

The discharge of the crest can be computed by following general formula:

$$Q = MLH^{3/2} \qquad (1)$$

in which, M is the discharge coefficient, 1.4 - 1.5 for flat crests and 2 - 2.1 for both round crests, L the length of the spillway and H the total head at crest.

As for the throw distance of the jet, it can be calculated as follows.

a) For flat crest (Fig.10a)

The depth at point B (h_B) can be calculated by following formula:

$$H = h_B + \frac{\phi^2 q^2}{2gh_B^2} \qquad (2)$$

in which, q is the linear discharge, ϕ the velocity coefficient, about 0.85, and g the gravitational constant. Thus the velocity at B is q/h_B and the throw distance of the jet (S) can be calculated by following formula:

$$S = \xi v_B \sqrt{\frac{2y}{g}} \qquad (3)$$

in which, y is the difference between headrace and tailrace, and ξ the energy loss coefficient, about 0.85 - 0.9.

b) For round crest with free fall (Fig.10b)

The depth and velocity at B can be calculated by following formula:

$$H + Z = h_B + \frac{\phi^2 q^2}{2gh_B^2} \qquad (4)$$

in which, Z is the elevation difference between the crest and point B, and $\phi \approx 1$.

Thus, $V_B = \frac{q}{h_B}$ and the throw distance of the jet can be determined by following formula.

$$y = \frac{gS^2}{2V_B^2\cos^2\theta_1} + S\,\mathrm{tg}\,\theta_1 \qquad (5)$$

in which, y is the difference between headrace and tailrace, and θ the slope angle with the horizontal.

c) For round crest with bucket (Fig.10c)

The velocity at B can be calculated by formula (4), with ϕ being 0.95, and the throw distance be calculated by following formula:

$$y = \frac{gS^2}{2V_B^2} - S\sin\alpha \qquad (6)$$

in which, α is the flip angle, preferably 10-15°.

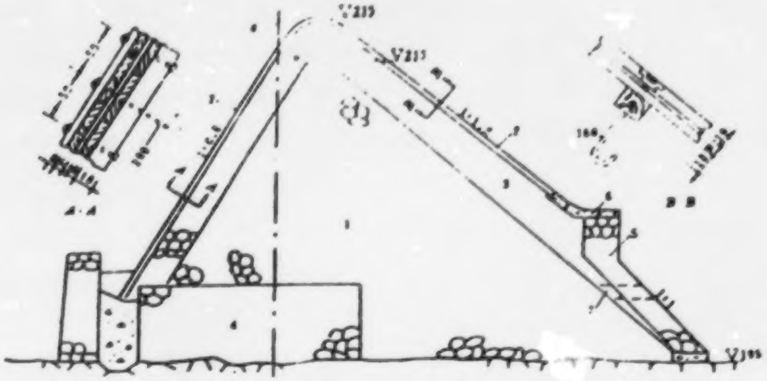
3. Other features, such as sloping core, filters, riprap protection, downstream scouring, etc. can be designed by general criteria of embankment dams.

This type of overflow dam can be applied to a dam height of less than 25m, with linear discharges of 2-3 m^2/s.

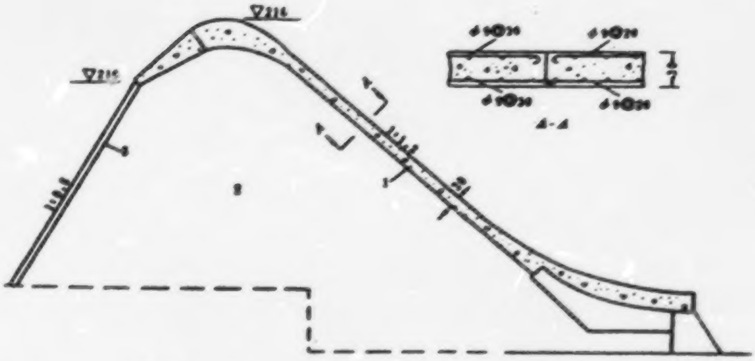
III Ruiguang Type of Overflow Rockfill Dam

This type of overflow rockfills came from the experience of old timber-deck rockfill dams, of which the timber deck was replaced by concrete slabs after its several years of operation. However, these rockfill dams were all of non-overflow type.

Fig.11 is the Ruigang overflow rockfill dam in Jiangxi Province, 20m high, completed in 1960. The rockfill was dumped with a porosity of 35-38% and retained by lime-mortar laid stones of less than 2m thick on both faces. Temporary timber deck within the water fluctuation zone was replaced by reinforced concrete slabs (Fig.11b). In 1971, a flood with a unit discharge of greater than 20m^2/s had safely passed through without any trouble or damage. This dam has been working well.



(a) overflow section and timber deck



(b) R.C.slabs on spilling face

Fig.11. Ruigang overflow rockfill dam

In Fig.11a,
1 - rockfill;
2 - timber deck;
3 - lime-mortar masonry;
4 - old masonry;
5 - cement mortar masonry;
6 - concrete bucket;
7 - drains;
8 - dam axis

In Fig.11b,
1 - concrete slabs;
2 - rockfill;
3 - timber deck.

The section of Ruigang dam is about 2 times of a gravity section, but the unit cost of rockfill was less than that of concrete by 7 - 8 times*. If the rockfill were placed by vibratory-rollers and both faces properly flattened, this type of overflow dam could be expected with greater security.

IV Hard-shell Type Overflow Rockfill Dam

Fig.12. is the Jiaoling dam in Guangdong province, 17m high for the overflow section and 19.4m high for the non-overflow section, completed in 1966. Its design unit discharge was 6 m^2/s, the porosity of rockfill was about 36%. The cement-mortar masonry and concrete slab were used as the impervious element. During its operation, the leakage amounted to 70 liter/s. Then a cement mortar layer of 5 cm thick was provided on the upstream face and the leakage discharge decreased to 10 liter/s. Up to now, floods have been passed frequently, without any trouble or damage.

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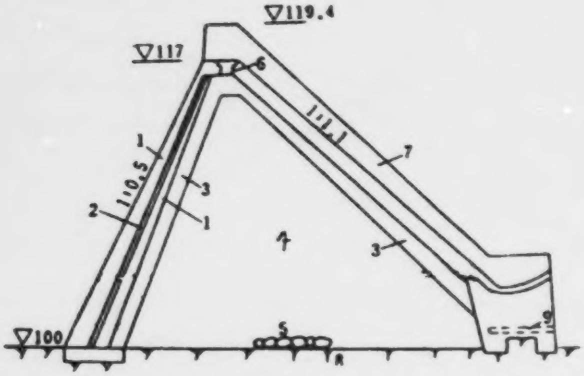
* In China, SHP projects were constructed by local government or community, with less amount of construction equipment than that of large hydros.



In Fig.12,
1 - cement mortar masonry;
2 - concrete slab;
3 - rubble masonry;
4&5 - rockfill;
6 - observation chamber;
7 - mortar-laid training wall;
8 - rock foundation;
9 - drains.

Fig.12. Jiaoling overflow rockfill dam

Fig.13 is the cross section of Baizhangji No.2 dam in Zhejiang province. The hearting area of the dam was dry-laid rubble, with an average porosity of 20%, corresponding to a unit weight of 2.1 T/m^3. The upstream zone was cement-mortar masonry, which was used as the impervious deck during initial impounding, and then sprayed with wire-fabric shotcrete of 2X3.5cm. The max. settlement during operation was 1.3 mm only, while its horizontal displacement of the dam 6.6 mm, the dam being elastically deformed. Since its completion in 1967, this dam has been working satisfactorily.

Above-mentioned type of overflow dam is commonly called in China "hard shell type", and widely used in SHP projects in mountainous or hilly areas. Its upstream slope is generally in 1:0.6-1:0.65 and the downstream one in 1:0.7-1:0.8 for dry-laid stones and in 1:1.1-1:1.2 for dumped rockfill. The upstream impervious membrane can be made of concrete slabs or wired shotcrete, with cushions of mortar-laid rocks. The downstream face should be kept non-vacuum during overflowing. Training walls are made of cement-mortar masonry, founded directly on the dam (if the hearting area is dry-laid or hand-placed) or on the competent foundation (if the dam is rockfilled).

The hard-shell type dam can be applied to a dam height of 30 m or more, with a unit discharge up to 20-30 m^2/s. Its main disadvantage is labor consuming and it is suitable for some developing countries where labor cost is low.

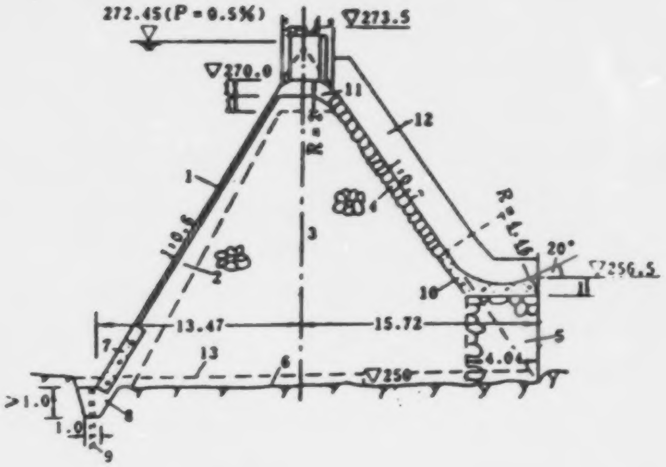


Fig.13. Baizhangji No.2 dam

In Fig.13,
1-shotcrete layer with wire fabric;
2-cement-mortar masonry;
3-dry-laid rubble, with porosity less than 25%;
4-cement-mortar ashlar stones, laid on edges;
5-cement-mortar masonry, with rocks weighing no less than 200 kg;
6-slightly weathered rock;
7-R.C.Slab;
8-concrete cut-off; 9-grouting, 4-6m deep; 10-R.C. bucket;
11-R.C.; 12-cement-mortar masonry training wall;
13-original ground surface.

V Concluding Words

1. A separate spillway could cost up to 30% of the total investment of the dam. However, overflow earthfill dams have more or less troubles after its completion. Combining the spillway with the rockfill dam is a development tendency in SHP civil works.

2. The Beliashevski type of overflow rockfills is suitable for dams in plain or semi-hilly areas and can be constructed in soft foundation materials, with a height of less than 8m and a unit discharges less than 5 - 20 m^2/s.

3. Chaoguche type and hard-shell type overflow rockfill dams are suitable for mountainous or hilly regions and generally constructed on rock foundation; the latter type can be applied to greater dam height and unit discharge.

4. The main disadvantage of overflow rockfill dam is labor consuming for the hand-placed rubble and mortar-laid masonry. This old technology has been favored in the SHP civil works of China because of: 1) cheap labor in China (however, the labor cost over the past 8 years escalated by 4-6 times); 2) saving cement and steel; 3) technical applicability of local people; 4) saving on formwork. In developing countries, especially where the labor cost is comparatively cheap, these types of overflow rockfills may be preferable.

5. According to author's analysis , among others, the main problem of overflow rockfills is the settlement of the embankment. The author had analyzed some settlement data of dumped and rolled rockfill dams (4); the vertical settlement of rolled rockfills was nearly equal to that of dry-laid ones, and the horizontal displacement of the deck-type rolled rockfills even smaller than that of semi-rockfill dam or hard-shell type rockfills. At present, the concrete-deck type rolled rockfill dam is one of development tendencies in dam engineering. Based on the experience as mentioned above, this type of rolled rockfills would further improve the performance of overflow rockfill dams.

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Siphon Penstock System for the Superior Dam Powerstation

By
J. Schmidt, W.R. Ivarson

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SIPHON PENSTOCK SYSTEM FOR THE SUPERIOR DAM POWERSTATION

Joseph J. Schmidt*
W.R. Ivarson**

Introduction

The Superior Dam powerstation is a small hydroelectric project owned and operated by the City of Ann Arbor, Michigan. The project is located at Superior Dam on the Huron River in the City of Ann Arbor.

Hydroelectric power was first developed at the site in 1920. This development consisted of an earth fill dam with a barrel arch spillway. The spillway had one foot high flashboards resulting in a normal difference between headwater and tailwater of fourteen feet. An integral intake powerhouse with two open flume vertical Francis turbines of 300 and 600 kW capacity generated power until the early sixties.

In 1963, Detroit Edison sold the facilities to the City of Ann Arbor for one dollar. In 1972, the City of Ann Arbor demolished the powerhouse as the most cost effective means of correcting their inability to buy liability insurance for the facilities.

As energy prices escalated in the seventies, redevelopment of electric power began to look viable. In 1980 the City performed a feasibility study and made application to the Federal Energy Regulatory Commission to be exempted from licensing while redeveloping the site for hydropower. The license exemption was granted in 1982 and the project assigned FERC project number 3152. Construction of the project began in February of 1985, and the unit was put into operation in June 1986.

Power generated from the project is sold to the Detroit Edison Company under the terms of a power purchase agreement signed between the City and Detroit Edison in May 1984.

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Project Description

The Superior powerhouse is located on the left bank of the Huron River immediately downstream of Superior Dam. Water is conveyed over the dam and to the turbine through an eight-foot diameter reinforced concrete penstock. The penstock is equipped with a siphon priming system that evacuates air from the high point of the penstock and draws the water up from the reservoir into the penstock. An air-vacuum valve is located immediately above the penstock high point on a reinforced concrete thrust block. A four-inch diameter vacuum line runs from the valve to two liquid ring vacuum pumps located in the powerhouse. A vacuum control tank is located above the pumps in the powerhouse.

Operation of the project is run-of-river with the headwater maintained at a constant level by discharging water through the unit or through the spillway radial gate or both combined. Flood discharges above their combined capacity are passed over the barrel arch spillway. A diagram showing the arrangement of the project features is presented in Figure 1.

The powerhouse is a reinforced concrete structure with a metal roof. The roof is equipped with a large removable metal hatch to provide access to the major equipment for installation or removal with a mobile crane. A large reinforced concrete thrust block surrounds the junction of the reinforced concrete penstock and the upstream edge of the turbine housing. This thrust block serves as the generator and speed increaser foundation. Water exits the turbine and powerhouse through a rectangular reinforced concrete draft tube. Bulkhead slots are provided at the end of the draft tube. The steel bulkheads are shared with another project and are transported when necessary. An access hatch is located on the roof of the draft tube. Dewatering of the unit is accomplished by installing draft tube bulkheads and pumping the water out with portable pumps.

The generating equipment in the powerhouse consists of an inclined shaft double regulated, propeller, S-type turbine that turns an induction generator inclined at the turbine shaft angle. A speed increaser is installed between the turbine and generator. Wicket gate and runner blade openings are operated by a hydraulic power unit located next to the turbine.

Current is passed from the generator through the switchgear and transformer and into the Detroit Edison electrical grid. Energy output is metered by Detroit Edison immediately outside of the powerhouse in the yard area.

The powerhouse is provided with a programmable controller which allows for automatic operation of the generating unit, siphon penstock system and spillway radial gate. The controller is located within the powerhouse next to the unit switchgear. The powerplant generates 570 kw at the rated net head of 14 feet and a hydraulic capacity of 567 ft^3/s.

The reinforced concrete penstock extends from the upstream face of the powerhouse, over the dam and down into the reservoir upstream of the dam. A reinforced concrete thrust block is located at the high point of the penstock and encases a forty-five degree penstock elbow. Concrete blocks with metal tie straps secure the penstock in place on the upstream slope of the dam. The penstock is buried between the powerhouse and the thrust block. An access hatch to the penstock is located next to the upstream wall of the powerhouse.

The intake to the penstock consists of a nine-foot diameter, forty-five-degree wye section of pipe connected through an eccentric reducer to the eight-foot diameter penstock. The upstream section of penstock rests on a twenty degree angle to the horizontal. The upstream faces of the wye are vertical and are fitted with brackets to accept removable trashrack panels. The steel trashracks provide for a three and one-half inch clear space between the rack bars. Eight panels approximately four feet-eight inches wide by two feet-six inches high are installed.

The air-vacuum valve and breaker valve for the siphon penstock system are located within a weatherproof, heated metal cabinet on top of the penstock thrust block. A four-inch diameter steel pipe vacuum line extends from the priming valve down to the vacuum pumps in the powerhouse. A vacuum control tank is located immediately above the vacuum pumps. A pump and float controlled water storage tank provide seal water to the vacuum pumps. Power for the vacuum and seal water pumps is supplied from an outside source.

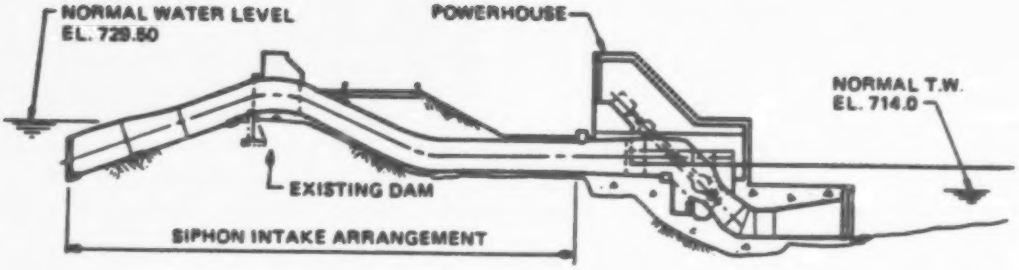

Figure 1 - General Arrangement of the Superior Dam Powerstation

Design

Design of the siphon penstock system was based on the site conditions and the requirements of the generating equipment. The design and selection of this generating equipment will not be presented here. Instead a brief summary is provided.

The equipment for the project was sized based on the river discharge and available head at the site. River discharge varies historically at the site from 50 ft^3/s to 18,000 ft^3/s with an average discharge of 275 ft^3/s. The economic choice of generating equipment had to be capable of operating at a low head and over a wide range of discharge.

The contract bid documents for equipment supply and installation allowed bidding of either one or two unit alternatives that would guarantee operation up to a discharge of 550 ft^3/s. The successful bidder elected to provide one S-type double regulated propeller turbine with a range of discharge from 100 ft^3/s to 570 ft^3/s. This turbine/generator set is a standard design item available from the manufacturer.

The selection of a single turbine for the project determined that water be supplied to the turbine through a single penstock. The penstock diameter was optimized by calculating head losses and costs for various penstock sizes and materials and comparing them to the expected revenue of the project. The resulting optimum diameter was determined to be eight feet. The following table lists the design values used in the design of the penstock and vacuum system.

Table 1

SIPHON PENSTOCK SYSTEM
DESIGN VALUES

Inside penstock diameter	8 ft
Penstock length	150 ft
Headwater elevation: (NGVD)	
Normal	729.5 ft
Minimum	728.0 ft
Tailwater elevation: (NGVD)	
Normal	714.0 ft
Minimum	713.5 ft
Top of penstock elevation	741.0 ft
Normal lift height for vacuum	11.5 ft
Vacuum pressure in crown	15 in of Hg
Penstock discharge	575 ft^3/sec
Pump requirements	
System volume	8,000 ft^3
Initial pressure	1 atmosphere
Final pressure	15 in of Hg
Air leakage	78 lb/hr
Evacuation time	20 min

Materials considered for penstock construction included steel, fiberglass and reinforced concrete. All three could be manufactured to withstand an internal negative pressure of 8 psi. The city of Ann Arbor chose the reinforced concrete with embedded metal cylinder option since it offered the greatest resistance to vandalism, a major concern at the project site. This type of concrete pipe is a standard design item readily available from water pipe manufacturers.

The penstock consists of approximately 150 feet of 8-foot diameter reinforced concrete with embedded metal cylinder pipe. The diameter of the penstock on the upstream slope of the dam is increased to 9 feet to connect with the intake, a 9-foot diameter, 45 degree wye section of penstock.

The penstock alignment allows for the encasement of the high point of the system, the forty-five degree elbow, in a reinforced concrete thrust block located near the top of the dam. The bottom of this thrust block is set at elevation 730.5, one foot above the reservoir normal water elevation, so as not to require cofferdamming in the upstream pool.

The portion of the penstock upstream of the thrust block is placed on a bed of gravel on the upstream slope of the dam. The intake to the system is a nine-foot diameter, wye section of pipe. An eccentric reducer transitions between the nine-foot diameter wye and the eight-foot diameter penstock. The upstream faces of the wye are vertical and fitted with brackets to accept removable trashracks. All of this construction was done without the use of a cofferdam.

The two nine-foot diameter openings were sized to limit water velocities through the intake to less than five feet per second. The top of the intake opening was submerged approximately four and one-half feet below the normal water surface elevation to eliminate any air entraining vortex conditions and to avert any complications from ice. A trashraking system was not designed as it was believed the backwash through the trashrack during unit shutdown would clean the racks of debris.

Stability of the penstock is provided by a combination of attached weights, thrust blocks, and burial in earth. The upstream portion of the penstock is tied with steel straps to concrete blocks set into the upstream gravel bed. The high point of the penstock is encased in mass concrete (thrust block) at the top of the dam. The portion of penstock between the dam and the powerhouse is covered with compacted backfill.

The vacuum system was designed to contain two vacuum pumps for redundancy to assure continued operation in case a single pump failed. During initial priming both will operate. The pumps will alternate operation to evacuate accumulated air during normal operation. The pumps would be located in the heated powerhouse to avoid complications from freezing. A system schematic of the vacuum system is shown on Figure 2.

The size of the pumps was selected to evacuate the penstock and start the unit in 20 minutes. However, the substitution during construction of smaller vacuum pumps, a smaller priming valve and a smaller 4-inch diameter air line rather than the specified 6-inch diameter line increased actual evacuation time to 45 minutes. The required vacuum pressure of 15 inches of mercury (17 feet of water) corresponds to the height that the water must rise within the penstock above the reservoir plus a safety factor of 5.5 feet of vacuum. The pumps are located in the powerhouse and a four-inch diameter steel pipe serves as the vacuum line to the air-vacuum valve located at the top of the penstock in a weatherproof, heated steel cabinet.

The air-vacuum valve allows air to be evacuated from the penstock until the water level rises up into the valve and a float closes the valve. A pressure sensor signals the vacuum pumps to stop and the unit wicket gates to open to begin generation when the vacuum is equivalent to a water level one foot above the air-vacuum valve. When the water level in the penstock drops due to the presence of accumulated air in the system, the valve will open and one vacuum pump will switch on to remove the air and close the valve. A solenoid valve, adjacent to the air-vacuum valve, will allow the vacuum to be broken for emergency shutdown of the system. Breaking of the vacuum eliminates flow through the unit. The purpose of the vacuum control tank is to provide a large enough volume of vacuum in the system to precisely control vacuum pressure.

The pumps, priming valve, breaker valve, air line and vacuum control tanks are all standard design items that are used regularly in manufacturing industries and medical facilities. An early estimate of the cost for the vacuum priming system was $23,300.00 not including installation.

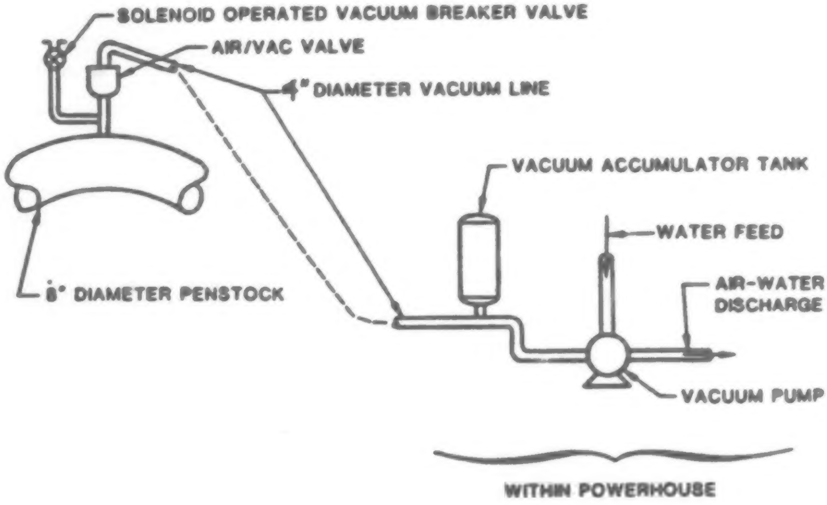
SOLENOID OPERATED VACUUM BREAKER VALVE
AIR/VAC VALVE
4" DIAMETER VACUUM LINE
VACUUM ACCUMULATOR TANK
WATER FEED
8' DIAMETER PENSTOCK
AIR-WATER DISCHARGE
VACUUM PUMP
WITHIN POWERHOUSE

Figure 2 - Vacuum System Schematic

Construction

The Superior Dam powerstation was determined to be marginally feasible from an economic standpoint. Design of the project was performed with the goal of minimizing construction costs while housing and protecting utility grade generating equipment. The existing downstream retaining wall was retained during powerhouse excavation to eliminate the need for a downstream cofferdam. Steel sheet pile was driven and anchored to portions of this wall to form the powerhouse tailrace wall.

The generating unit was placed on a forty-five degree angle to minimize the length and depth of the powerhouse. The siphon penstock system was selected to eliminate the need for cofferdamming upstream of the dam or lowering the reservoir and to eliminate the need for dam removal and restoration. Selecting prefabricated pipe for the penstock and intake allowed for their installation underwater using a crane, thus being consistent with eliminating any dewatering requirement. As noted earlier, the turbine/generator set, concrete penstock and vacuum system equipment are all standard design items.

Construction began in February 1985 with the contractor, Greenfield Construction Co., driving sheet pile for the tail channel walls with a pile driving attachment to his construction crane. Excavation of the powerhouse and tailrace followed immediately using excavation attachments to the same crane and backhoes in tighter areas. Minor leaks through the existing retaining wall were grouted where possible with a small portable grouting machine in order to reduce pumping requirements while maintaining the excavation in a dry condition.

The powerhouse is founded on soil. After excavation and prior to the concrete placement, six inches of compacted granular backfill was placed. This provided a firm base for the foundation slab. Concrete was obtained from a commercial off-site source and delivered to the site premixed. A steel sheet pile wall was driven below the end of the draft tube to underpin the powerhouse foundation for erosion protection.

The turbine steel draft tube cone was embedded in the powerhouse substructure. The concrete draft tube was poured around plywood formwork. The turbine pedestal supports were poured and turbine anchor bolts set. The penstock thrust block was poured around a prefabricated metal cylinder with exposed flanges which later would be bolted to the penstock on the upstream side and to the turbine runner housing on the downstream side. Anchor bolts for the generator and speed increaser were set on top of the penstock thrust block. The portion of the powerhouse floor slab beneath the switchgear was poured as a slab on grade with grade beams and foundation walls.

The reinforced concrete powerhouse walls were poured and the powerhouse metal roof assembled on site. The removable hatch was assembled in place on the roof and removed for placement of the generating equipment.

The remainder of the turbine parts; runner, turbine shaft and runner housing were lowered by mobile crane through the roof hatch and assembled. The generator, speed increaser and connecting shaft were also lowered through the roof hatch and assembled. The vacuum pump system was rolled in through the large access door and bolted in place. During construction, a large steel hook was embedded in the upstream powerhouse wall to support the generator in place while the generator base was bolted and grouted.

The penstock alignment was excavated concurrently with powerhouse construction. A portion of the dam above elevation 730.5 (NGVD) was removed for placement of the penstock thrust block. A forty-five degree reinforced concrete penstock elbow was embedded in the thrust block with a 4-inch diameter tap at the top for the siphon system.

Penstock bedding consisting of sandy gravel was placed and compacted to a depth of one foot below the penstock sections. The prefabricated penstock sections were lowered into the excavation by a mobile crane. Their connections are bell and spigot type joints with a rubber gasket. The inside and outside joint edges were sealed with epoxy mortar. To allow for differential settlement along the penstock the internal steel cylinders in the penstock sections were not welded together. The portion of penstock between the powerhouse and the thrust block was covered with backfill and compacted to dam construction specifications. An access shaft with a bolted hatch cover was prefabricated onto the section of penstock to be installed adjacent to the powerhouse.

A one-foot deep trench was dredged on the upstream slope of the dam for the penstock and intake. Prefabricated concrete anchor blocks with embedded threaded rods for steel straps were placed in the trench by a mobile crane. Penstock bedding material was placed and compacted in the trench. The intake wye section, reducer and adjacent section of penstock were assembled on shore and lowered into the reservoir onto the anchor blocks and bedding. Special counterweighting of the crane was required to place this 130,000 pound section of pipe. Alignment with the embedded 45-degree elbow was made and the joint secured. The steel tie straps were installed and secured by a diver and bedding material poured around the base of the penstock. The brackets for the intake trashracks were also installed on shore prior to placing the assembly. The trashrack panels were lowered into place by a crane and guided by a diver.

The 4-inch diameter vacuum line was installed as the penstock backfilling was performed. Connections were made to embedded flanged pieces at the powerhouse and the thrust block at the penstock high point. The air-vacuum valve and solenoid operated vacuum breaker valve were installed in a NEMA quality metal enclosure on top of the penstock thrust block. A heat lamp was added within the enclosure to protect against freezing.

The two liquid ring vacuum pumps were supplied on their own metal base which was bolted to the powerhouse floor. A sixteen-inch diameter vacuum control tank was connected to the vacuum line with a two-inch diameter tap. This four-foot, three-inch high tank was mounted above the pumps. Station service power is taken from Detroit Edison which in turn provides power for the pumps. Seal water is supplied to the vacuum pumps from the tailrace by a 0.5 horsepower pump. Embedded piping was installed to carry used seal water to the powerhouse sump. Embedded piping was also installed to carry sump pump discharge to the tailrace.

Electrical controls, instrumentation, switchgear, and the main power transformer were installed by Westinghouse. Power cables are installed from the transformer to the Detroit Edison metering equipment and then to their transmission line. The unit was tested and placed into commercial operation in April 1986. The contractor remained on site, however, till June 1986 to complete project construction outside of the powerhouse. The estimated and conctract costs for the project are presented in Table 2.

Table 2

PROJECT COSTS

	Engineer's Estimate	Bid Award
Equipment Contract	$ 760,000	$1,162,527[1/]
General Construction Contract	$ 755,000	$ 703,000
Total	$1,515,000	$1,865,527

1/ Includes a deduction of $35,575 for simultaneous award of the equipment supply at Barton Dam.

Operation

The Superior Dam powerstation is operated on a run-of-river basis. The reservoir water level is maintained at a constant level while the reservoir inflow is matched by discharges downstream through either the unit or radial gate spillway or the combination of both. Flood inflows larger than the capacity of the unit and radial gate will raise the reservoir water level and allow excess water to spill over the ungated barrel arch spillway. The unit is capable of automatic or manual operation. Automatic operation is achieved through the use of the programmable controller (PC) located in the powerhouse. Unit start-up is automatic with the presence of an operator required to initialize the system by unwatering the penstock. The unit operates year round and there is no change in operating procedures from summer to winter.

Start-up of the unit is controlled by the programmable controller (PC) in the powerhouse. An operator checks that the turbine wicket gates are closed and power is supplied to the vacuum pumps. The vacuum pumps have preset limits of operation. When pressure in the system is above -6 psi gage pressure the pumps will switch on. When pressure in the system is below -8 psi gage pressure the pumps will switch off.

For start-up, the operator switches the unit to run and both vacuum pumps begin to evacuate air from the penstock. The water level in the penstock rises to the top and up into the air-vacuum valve. The rising water level closes a float controlled ball valve in the air-vacuum valve. The closing of the ball valve causes the vacuum in the 4-inch diameter air line to rise quickly. When the vacuum pressure falls to the desired lower limit of pump operation (-8 psig), the pumps switch off and a signal is sent to the PC which signals the hydraulic power unit through the electronic governor to open the wicket gates on the unit.

The water proceeds to flow past the runner blades and rotate the shaft. The unit then adjusts runner blade and wicket gate position automatically by means of the PC to match the unit discharge and speed with the system frequency.

Once started the unit will operate automatically by means of the programmable controller (PC). A headwater float level sensor relays the reservoir water level to the PC. A change in water level will cause the PC to increase or decrease the wicket gate openings to increase or decrease discharge through the turbine. The hydraulic power unit will adjust the runner blades position and wicket gate opening. The turbine discharge range is from 100 ft^3/s to 570 ft^3/s.

When the reservoir water level continues to rise and the unit maximum discharge has been reached, the PC will signal the spillway radial gate to open. The radial gate will be raised in increments until the reservoir water level restabilizes at elevation 729.5. When river discharge into the reservoir exceeds the combined capacity of the unit and radial gate spillway, the reservoir water level will rise above the top of the flashboards on the crest of the barrel arch spillway and spill downstream. Conversely, as reservoir water level drops the PC will adjust the radial gate position and/or unit discharge to maintain the reservoir water level at elevation 729.5.

Water contains dissolved gases in solution. When subjected to negative pressures, some of these gases come out of solution and collect at the high point in the penstock. The presence of this air reduces the vacuum pressure (increases gage pressure) in the system and is detected by the vacuum gauge below the air-vacuum valve. When this pressure increases to -6 psig, one vacuum pump switches on and evacuates air from the system. The removal of this air causes the water level in the penstock to rise and close the ball in the air-vacuum valve. Once the air-vacuum valve is closed the system pressure drops to the pump lower limit of -8 psig at which point the pump switches off. The system then resets to use the other pump for the next cycle.

Debris collects on the trashracks during the summer months of operation. This flow restriction occasionally leads to automatic shutdown of the unit. While the racks were designed to be cleaned by the backwash during shutdown of the unit and unwatering of the penstock, this does not always occur since the velocity of the outrushing water is limited by the velocity of air through the 4-inch diameter vacuum breaker valve.

Shutdown of the unit can be achieved manually or will occur automatically when conditions for continued operation cannot be achieved.

The turbine can be manually shutdown by closing the wicket gates with the hydraulic power unit. Automatically this will occur when there is not enough water pressure in the penstock to run the turbine.

The unit will also shutdown automatically when the reservoir level continues to drop even as unit discharge is decreased to a minimum of 100 ft^3/sec.

Emergency shutdown of the system can be achieved by opening the 4-inch breaker valve between the air-vacuum valve and the top of the penstock. This valve can be opened locally or through the PC in the powerhouse. Once the valve is opened, air rushes into the penstock, the siphon is broken and water will stop flowing through the turbine.

On July 17, 1987 the Superior dam turbine was inspected by Harza Engineering Company at the request of the city of Ann Arbor. No evidence of cavitation pitting or erosion damage to the runner blades or discharge ring was found.

The Superior kilowatt-hour meter registered 3,219,690 kW-hrs generated as of July 17, 1987. This meter was installed in September 1986 and from that time till July 1987 the unit had been on-line for 6,916 hours. Assuming the unit was on line 75 percent of the time due to low river flows from its late June 1986 commissioning date to September of 1986 allows us to add 1,080 hours to its on-line time (2 mos x 30 days x 0.75 = 1,080 hr). The total on-line time is then 7,996 hours as of July 17, 1987 (7,996 = 1,080 + 6,916). The approximate average output of the Superior unit is then computed to be 403 kW.

A capacity test performed in June 1986 verified that the unit generates the required power in the range from 83 kW to 574 kW for the specified discharge range from 100 ft^3/s to 567 ft^3/s.

Maintenance

The operation and maintenance of the Superior Dam powerstation is the responsibility of the city of Ann Arbor Water Department. They are responsible for the operation and maintenance of the city's water supply and sewer systems. There is one operator assigned to the four dams and two hydroelectric powerstations in the city. The second hydroelectric station is the Barton Dam powerhouse which was redeveloped in conjunction with the building of the Superior Dam powerstation.

The Superior Dam powerstation is an unmanned facility designed for automatic operation. The generating system installed was designed to require a minimum of maintenance and service.

The one operator visits the Superior Dam powerstation on the average once a day. He tours the facility and looks for any signs of vandalism. He then enters the powerstation and determines the status of the unit. Should the unit not be operating he will initialize the system and start-up the unit. Further problems would require additional inspection of the unit and its support equipment.

The operator also checks the intake area to determine if any debris has accumulated on the trashracks. Debris is removed from the trashracks by hooks and ropes operated from a small boat. During a recent one year facility inspection in July 1987 divers were able to clean the trashracks by hand.

Once a year the unit is dewatered to perform maintenance on the turbine. The wicket gates and runner blades are inspected for cavitation damage and their range of movement checked. The water passages are checked for cavitation damage.

The draft tube is dewatering by placing stop logs in the draft tube slot and pumping out the water with submersible pumps. However, during a recent one year inspection the availability of commercial divers in the area allowed the city to have the draft tube and runner blades inspected while under water.

The generator is inspected and cleaned once every six months. The unit is stopped and the generator de-energized. All other systems are scheduled for maintenance and service on a yearly basis. During these six month and yearly maintenance shutdowns the vacuum pump system is checked and serviced if necessary. The motors are checked and lubricated and the vacuum pump descaled in accordance with the manufacturers instructions. The priming valve is disassembled and checked for smooth operation. Vacuum gages are tested and replaced if necessary.

The first one year inspection of the turbine was performed on July 17, 1987 and revealed that the generating unit was in good condition with no cavitation damage to the runner blades or wicket gates. There was slight erosion of the concrete in the draft tube at the junction of the steel draft tube liner. This concrete was repaired by the divers.

Summary and Conclusions

The installation of the siphon penstock system at the Superior Dam site offered an economical solution to reinstalling hydro power at the site. The savings in construction costs that were realized by eliminating expensive cofferdamming in the reservoir and breaching of the dam helped make the project economically feasible.

With the proper operation and maintenance of the supporting pumps and trashracks the siphon over the dam can be maintained continually and will allow power generation to proceed without interruption. Use of the siphon penstock arrangement can be made at other low head sites where the lift of the water over the dam is limited to approximately 2/3 of the actual atmospheric head at the site.

A New Stainless Steel Alloy for the Hydroelectric Industry

By
W.J. Schumacher

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A New Stainless Alloy for the Hydroelectric Industry

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Abstract

Over the last 20 years, more and more stainless steels are being used in hydro machinery because of their reliability and ease of maintenance. The cast grade CA-6NM is very popular for turbine components like runners and wicket gates, but has become marginal under some operating conditions today.

This paper introduces Armco's NITRONIC 60* to the hyrdo industry by comparing CA-6NM and NITRONIC 60 with respect to corrosion, wear and cavitation properties.

Introduction

It has been over 20 years since the cast stainless, CA-6NM, was introduced to the hydroelectric industry.[1] This low carbon, martensitic alloy has improved impact strength, weldability, temper embrittlement and corrosion resistance compared to CA-15 (AISI 410). However, recent experience by some users has been less than satisfactory because of more severe operating conditions where the effects of corrosion and cavitation have taken their toll on this "super 13 Cr" alloy.

Because of those more severe operating conditions, there has been a growing need for improved stainless alloys for hydroelectric service. The precipitation hardening stainless, CB-7Cu (17-4 PH), has attracted some attention. More recently, higher chromium versions of CA-6NM, such as 16Cr-5Ni, are being studied in some detail.[2, 3] While these higher alloyed martensitic stainlesses have improved corrosion resistance over CA-6NM, they have very poor wear characteristics despite relatively high strength and hardness.

In the mid-1970s, Armco introduced NITRONIC 60 as a wrought, austenitic stainless steel with wear and galling properties approaching the much more expensive cobalt wear alloys.[4] With the success of the wrought product form, the cast form was soon developed. NITRONIC 60 is now included in two casting specifications, ASTM A351 and A743; its cast designation is CF-10SMnN. This paper compares CA-6NM and NITRONIC 60 in the important characteristics of corrosion, metal-to-metal, and liquid-to-metal (cavitation) wear. In the wear program, 17-4 PH at Rockwell C43 hardness was also evaluated.

Procedure

Laboratory castings were produced using cast iron molds. CA-6NM was cast into 1"x3"x8" (25x75x200mm) sections and CF-10SMnN was cast into a 3"x3"x10" (75x75x250mm) section. The analyses and conditions of these castings are shown below.

CA-6NM

Weight %

C	Mn	Si	Cr	Ni	Mo	N
.037	0.62	0.48	12.96	4.01	0.68	-

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*Registered trademark of Armco Inc.

Heat Treatment	Hardness (Rockwell)
1925F-30 Min.-Air Cool +1150F-4 Hrs.-Air Cool	C26

CF-10SMnN

Weight %						
C	Mn	Si	Cr	Ni	Mo	N
.077	7.59	3.68	17.38	8.33	--	.13

Heat Treatment	Hardness (Rockwell)
1950F-30 Min.-W.Q.	B90

Notice the high silicon which promotes fluidity and good castability in the CF-10SMnN. The cast form of NITRONIC 60 was evaluated in the corrosion tests and the wrought form for the wear tests. The wear of CF-10SMnN (cast NITRONIC 60) would not be expected to exceed the wear of wrought NITRONIC 60 by more than 10%.

Marine atmosphere corrosion was evaluated using a 5% salt spray test. The results in Figure 1 show that CA-6NM rusted badly, while the cast NITRONIC 60 (annealed) was totally unaffected. Even the unannealed NITRONIC 60 rusted less than CA-6NM. However, annealing is recommended to ensure the best corrosion resistance and mechanical properties.

CF-10SMnN also had far superior aqueous corrosion and pitting resistance compared to CA-6NM. In non-oxidizing acids like hydrochloric and sulfuric, CF-10SMnN was about two orders of magnitude better as shown in Table 1. The pitting resistance (10% ferric chloride) and resistance to oxidizing acids (nitric) of CF-10SMnN were also much better than the 13 chrome alloy as illustrated in Table 2.

Table 1 - Comparative Corrosion of CF-10SMnN and CA-6NM

	IPY (mm/y)			
	CF-10SMnN		CA-6NM	
1% HCl @ 35C	.011	(.28)	0.75	(19.0)
2% H_2SO_4 @ 80C	.039	(.99)	2.19	(55.6)
65% HNO_3-boiling	.043	(1.09)	.156	(3.96)
10% $FeCl_3$-R.T. (Pitting)	.043	g/in^2	.329	g/in^2

Wear

Many types of wear may be encountered by hydro machinery. Although most turbine components are designed with clearances, misalignment on these large structures may occur and cause metal-to-metal contact. One example is the seal ring. Such contact usually results in severe surface damage called galling. It is well-known that cavitation damage is a major concern in hydro equipment such as wicket gates, runner blades, and pump impellers. Under some operating conditions, silt may cause abrasive wear which rapidly accelerates metal loss to critical components.

Over a decade of experience has demonstrated that NITRONIC 60 has the best galling resistance of all stainless steels.[5] In contrast, low carbon, martensitic alloys like 17-4 PH and CA-6NM, despite relatively high hardness, have very poor sliding compatibility with other standard stainlesses. In the Armco button and block galling test, CA-6NM exhibited severe galling at 2.3 ksi against Types 410, 303 and 17-4 PH and good compatibility mated to NITRONIC 60 up to 39 ksi. See Figure 2. NITRONIC 60 will not gall at 50 ksi when mated to most of the standard stainless steels under these same test conditions.[6]

If catastrophic galling does not occur, the rubbing surfaces will wear down at some unknown rate. This type wear was measured by the crossed cylinder test method (ASTM G83). The results in Table 3 show that NITRONIC 60 was far superior to both CA-6NM and 17-4 PH at 105 and 415 RPM. The high work hardening capacity and oxide film formation of NITRONIC 60 make it comparable to cobalt and nickel base wear alloys. Similar results for abrasive wear are shown in Table 4.

Table 3 - Self-Mated Wear ASTM G83

Conditions - 16 lb. (71N) Load, 0.5 inch (12.7mm) Diameter Crossed Cylinders, Dry, R.T., Duplicates

	Weight Loss (mg/1000 rev.)		
	CF-10SMnN (HRB 95)	CA-6NM (HRC 26)	17-4 PH (HRC 43)
105 RPM 10,000 rev.	3.4	130	52.8
415 RPM 40,000 rev.	1.0	57.0	12.1

Table 4 - Abrasive Wear (Bonded SiC)

Conditions - 16 lb. (71N) Load, 10,000 rev., Dry, R.T., Triplicates

	Volume Loss (mm^3)		
	CF-10SMnN (HRB 95)	CA-6NM (HRC 26)	17-4 PH (HRC 43)
100 RPM	7.3	66	104
415 RPM	7.7	119	38

Cavitation damage can be severe if equipment is out of balance or water velocity is very high. It can cause noise and tends to pit the surfaces; this can result in a loss of efficiency. Independent laboratory testing of

NITRONIC 60 from outside sources[7, 8], has shown NITRONIC 60 to be significantly better than CA-6NM and to other austenitic stainless steels. These cavitation-erosion results, evaluated by two different methods, are shown in Figure 3. Other data in reference 7 indicate that NITRONIC 60 is even better than precipitation hardening stainless alloys with a tensile strength of 226,000 psi.

The Tennessee Valley Authority has been evaluating many coatings, wrought alloys and weld overlay deposits regarding their relative cavitation erosion resistance.[9] Some preliminary results using a jet stream at 4,000 psi are listed here.

	Erosion Rate (mg/hr)
Cobalt Alloy 21 Weld Overlay	0.9
Cobalt Alloy 6 Weld Overlay	2.2
Armco NITRONIC 60	2.5
Armco NITRONIC 60 Weld Overlay	2.9
Type 309 Weld	9.1
Type 308 Weld	9.8
Type 316 Weld	13.4
Carbon Steel	15.9
Al Bronze Weld	36.0

Summary

1. NITRONIC 60, compared to CA-6NM, has far superior: corrosion, galling, wear and cavitation resistance.

2. NITRONIC 60 is readily castable and is listed as CF-10SMnN in ASTM A351 and A743.

3. NITRONIC 60 is being used in hydroelectric applications for: turbine shaft sleeves, runner blade weld overlay, wear rings, nuts and bolts.

Several additional areas of application are under study and experimental field test results should be available over the next year.

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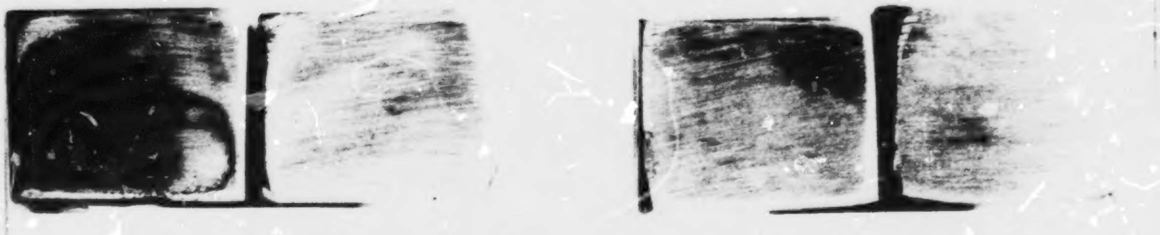
FIGURE 1

Corrosion Resistance of Cast NITRONIC 60 in 5% Salt Spray - 500 Hrs. @ 95°F

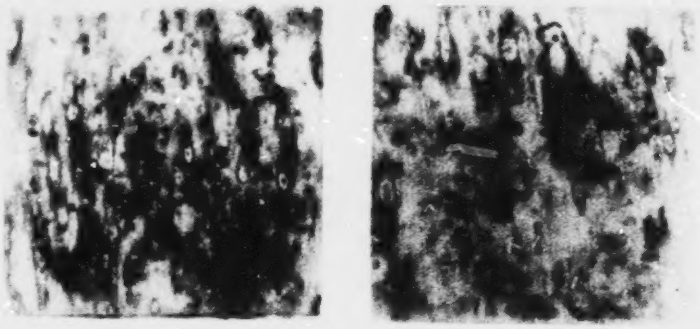


Nit. 60 Cast

Nit. 60 Cast-Ann

RLP 7624

Mag. 1.5X

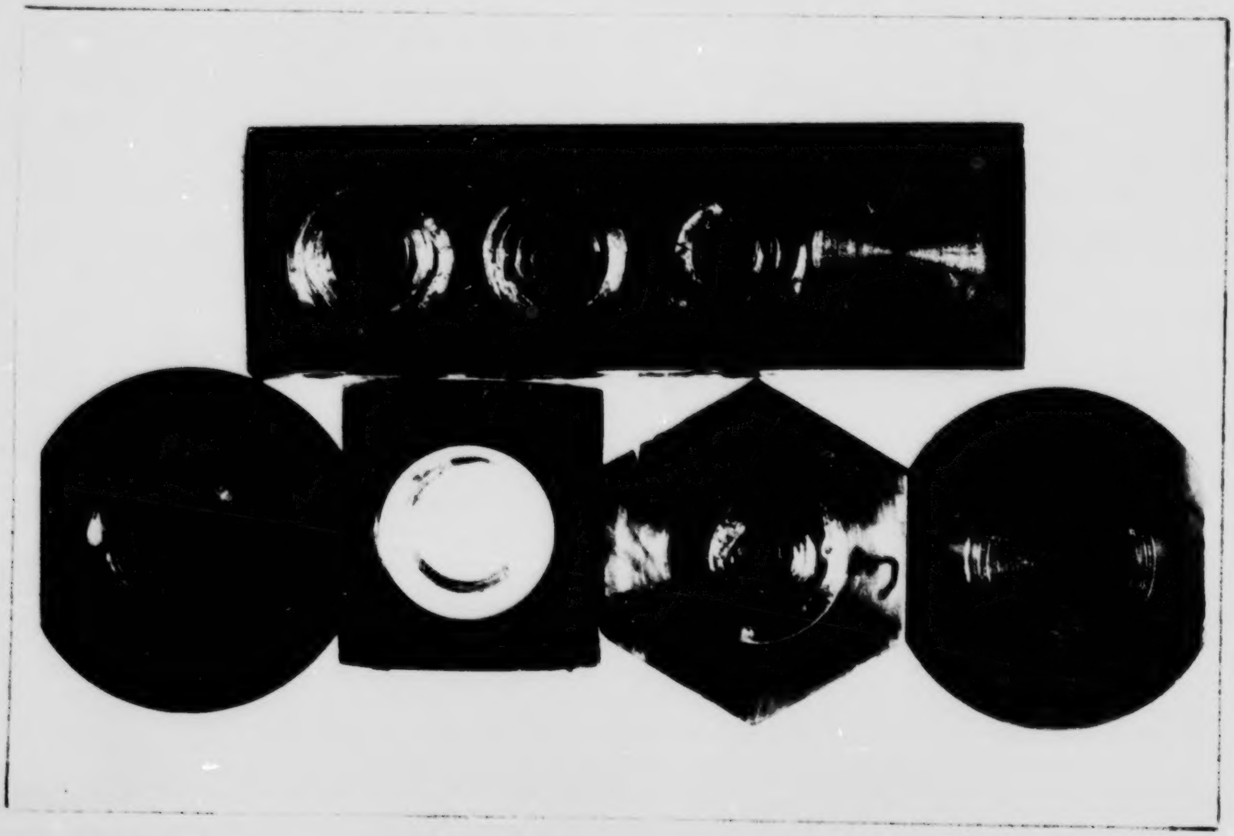


CA-6NM Tempered

FIGURE 2

GALLING OF CA-6 NM
1 REV. @ STRESS INDICATED

CA-6 NM BLOCK (HRC 26)



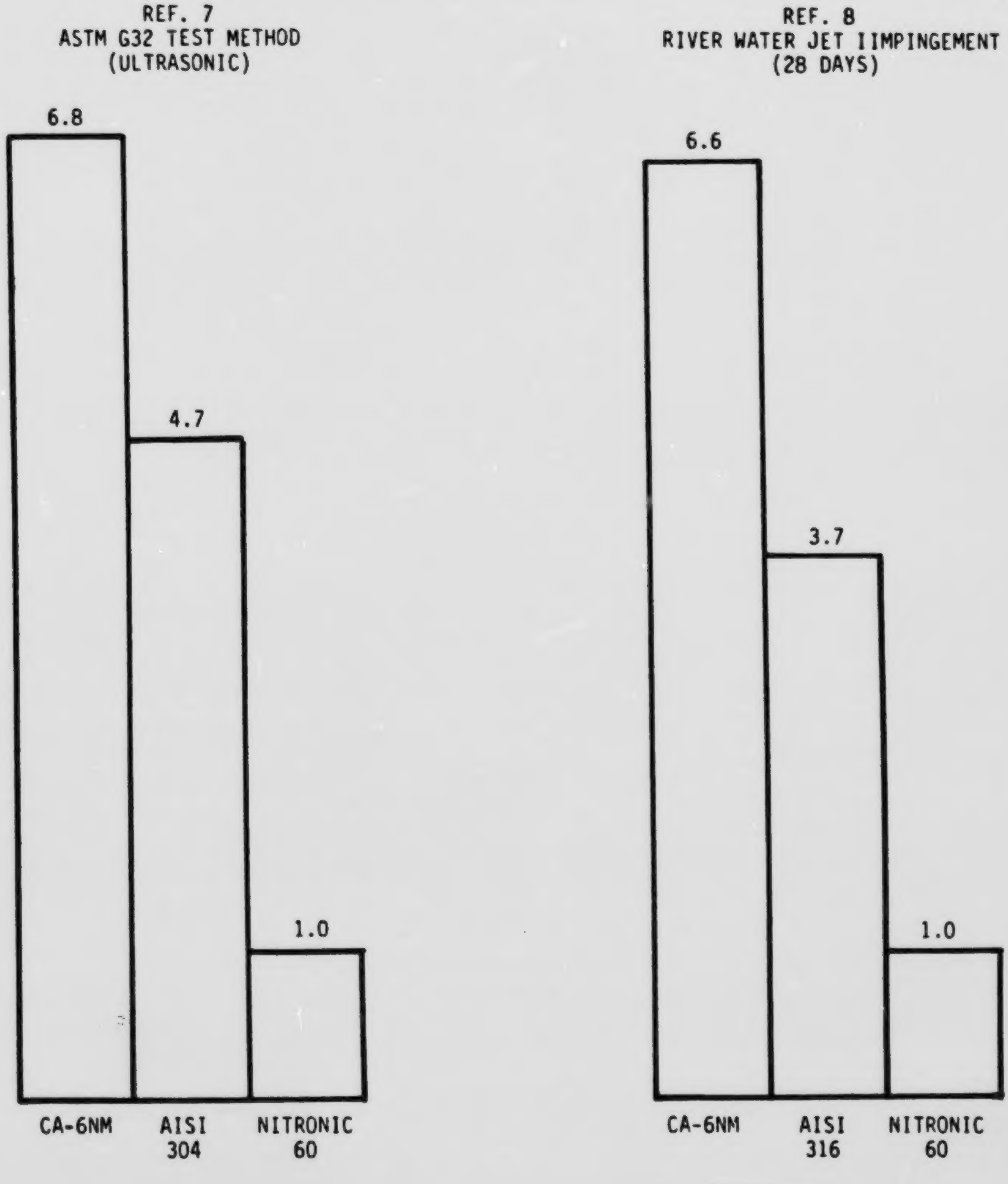
T410	17-4 PH	T303	NITRONIC 60
HRC 40	HRC 42	HRB 82	HRB 95
2.3 KSI	2.3 KSI	2.3 KSI	28* KSI

*THRESHOLD STRESS - 39 KSI

FIGURE 3

CAVITATION-EROSION OF STAINLESS STEELS

RELATIVE DEPTH OF DAMAGE



SESSION 18:

CONTROL EQUIPMENT

Chairperson: M. Dickson
Albery, Pullerits, Dickson

Optimizing Fluctuating Flows

By
A. Patzig

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OPTIMIZING FLUCTUATING FLOWS

Alfred F. A. Patzig, Eng.
Executive Vice President
Ossberger Turbines, Inc.

A standard, high speed turbine with good peak efficiency is perfectly suitable for constant water flows. However, at sites with fluctuating flows, a strong case can be made that a sub-divided Cross-Flow Turbine offers better rentability due to higher annual energy production, lower purchase price and installation cost.

PLOTTING A FLOW DURATION CURVE

The most important criteria of a site is the existing water flow data. The regional office provides data of each gaging station, from which a flow duration curve can be plotted. This graph will show the expected annual flow and how the water flow is affected monthly or daily for each of the pertaining hydro sites. The flow duration curve also reveals the consistency of the water flow and the difference between minimum and maximum flow. Knowledge of the flow characteristics is a prerequisite in determining the right turbine system to optimize utilization of the available resource. In this regard, it's important to remember that water turbines are essentially differentiated by turbines with high or low specific speeds, call high- or low-speed runners.

FLAT EFFICIENCY CURVE OF THE LOW -SPEED RUNNERS

High-speed runners have an efficiency characteristic with a high peak efficiency at approximately 3/4 turbine opening, falling below 80% at half turbine opening. Low-speed runners do not reach high peak efficiencies. Instead, they have a flat efficiency curve of 80% from full opening down to a partial opening of 1/3. As might be expected, all turbine manufacturers are trying to improve their equipment to better adapt the varying flow through constructive measures. Examples of these efforts include:

The Francis Turbine is offered with a single or double runner of medium specific speed, provided the additional costs permit such designs.

The Kaplan Turbine improves its efficiency through adjustable blade and wicket gates (A double regulated Kaplan turbine maintains good efficiency from 1/1 to 1/5 flow).

The Cross-Flow Turbine, designed in a two-cell configuration, (ratio being 1:2, maintains good efficiency from 1/1 to 1/6 flow.

The Pelton Wheel can be built with multi-nozzels to obtain a speed range, where flow variations from 1/1 to approximately 1/6 flow are permissible.

All these measures are aimed at reaching maximum annual energy production. For run-of-the-river plants, it is the energy production in kWhs that is the critical factor, as opposed to the peak output, (Which is important for demand power stations) Figures 1 and 2 illustrate optimum utilization for run-of-the-river power stations.

Essentially, the flow characteristic at most rivers during a one year period is similar to the one illustrated in Figure 1. Comparing the production range of a high-speed Francis Turbine with a low speed, two-cell Cross-Flow Turbine, it will become clear that, for the same hydro site, the latter can be designed for a 50% larger capacity (Qmax = 225 cfs), without Loosing in the partial opening range (Qmin = 37.5 cfs). Therefore, the Cross Flow Turbine provides additional generation at full flow for approximately 100 days a year and at partial flows for another 130 days a year. (Additional energy production is represented by the cross-hatched area of Figure 1). Inn the field this theoretical explanation is often acknowledged.

A different explanation for the surplus generation is given in Figure 2, where the efficiency curve of a two-cell Cross-Flow Turbine is compared to a Francis unit of equal specific speed.

In order to assess the installed capacity for a hydro power site, the revenue or profit must be compared with the investment cost. Assuming that the engineering and planning costs for a hydro power station, including the powerhouse and civil structures, are the same for all turbine types, one must first consider the equipment cost for an economic comparison. While water turbines (particularly smaller units), need to be individually sized to the existing site conditions, namely flow and head, there is dome room to compromise when it comes to the design parameter.

Radial type turbines require modular standardization at staggered turbine sized. Each individual site requires selection of a turbine size, closes to the standard unit.

Cross-Flow Turbines, with their cubical housing and the cylindrical drum type runner, are much easier sized. In their case, modular standardization is based on a single component, like the turbine runner diameter. As a result, each runner diameter is basically fixed by it dimensions (width x height). All other components are Fixed to fit each standard runner, i.e. the turbine housing side plates, bearing block assemblies, guide vanes and runner profiles are identical. The third dimension, the length is variable. Therefore, the runner length and intake nozzel can be exactly sized to suite the design flow.

WHAT ABOUT KAPLAN TURBINES

Standardized Kaplan Turbines normally do not reach the required Head/Flow ratio, which is so important for small hydro power plants, without essentially increasing the manufacturing costs. The double regulated Kaplan Turbine and the multi-nozzeled Pelton Wheel are not available at comparable costs for output ranges below 500 kW.

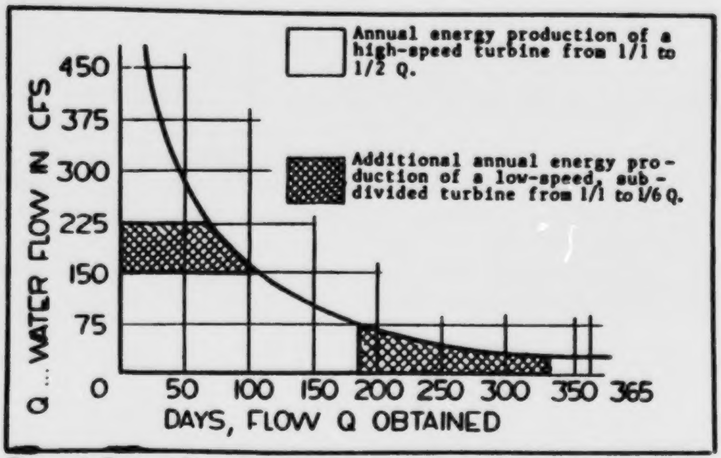

Figure I: Typical Flow Duration Curve: Very high flows last only a few days. A low-speed two-cell Cross-Flow Turbine can be designed 50% larger than a high-speed Francis Turbine, without restricting generation at partial flows. A Cross-Flow Turbine generates 100 additional days per year at high flows and 130 days at low flows. (cross-hatched area = additional energy). Courtesey of Ossberger

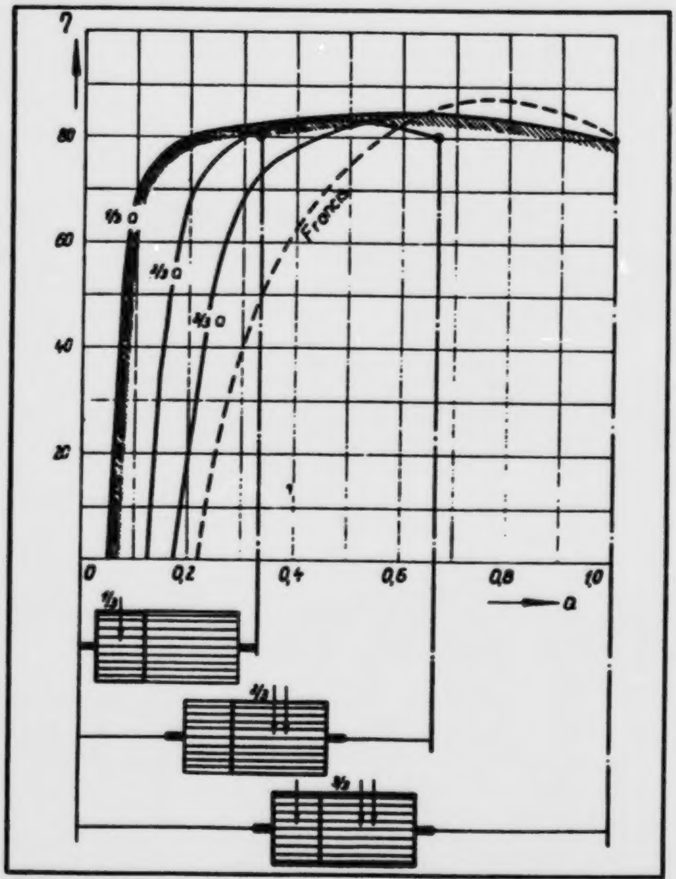

Figure II: Comparison between Francis and two-cell Cross-Flow Turbine efficiency curves with equal specific speeds. (courtesy of Ossberger)

Facts & Fictions of Hydraulic Turbine Speed & Load Control Systems

By
D. Purzycki

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Facts and Fictions of Small Hydraulic Turbine Speed and Load Control Systems

by Daniel Purzycki, P.E.

Abstract

There seems to be a great deal of confusion about what is required to control speed and load of small hydraulic turbines. This paper will explore governors and positioners and how they should be applied to various control arrangement. The approach will be that of defining the control strategy, presenting a practical solution, and discussing the relevant theory. Case studies will be presented on both isolated and infinite bus operations.

Before examining various control arrangements we will first define some terms used in this paper.

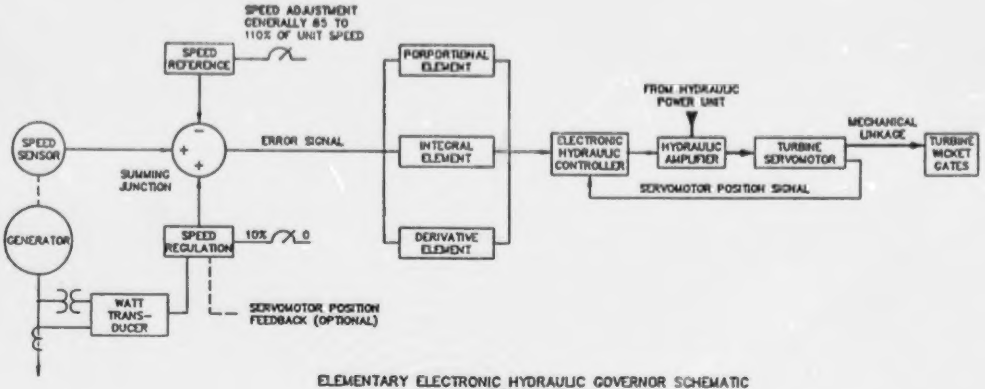
Glossary of Terms

Governor System: The combination of devices and mechanisms, which detect speed deviation and convert it into a change in servomotor position. It includes the speed sensing elements. The governor control actuator, the hydraulic pressure supply system, and the turbine control servomotor.

Positioner System: The combination of devices and mechanisms, which are capable manually or through automation hardware of adjusting the position of the servomotor for load and/or speed control. Included in this system is the hydraulic pressure supply system, positioner actuator, and turbine servomotor.

Infinite Bus: A source of voltage constant in phase, magnitude, and frequency and not affected by the amount of current drawn from it. It may be regarded as a bus to which machines having an infinite aggregate rating are connected or, in other words, as a machine having zero impedance and infinite inertia. A large power system often may be regarded as an infinite bus.

Isolated Bus: A bus that is fed by a generator or group of generators in which voltage and frequency are modified by changes in field excitation levels or power input by an individual unit.


SPEED ADJUSTMENT GENERALLY 85 TO 110% OF UNIT SPEED
SPEED REFERENCE
PORPORTIONAL ELEMENT
FROM HYDRAULIC POWER UNIT
MECHANICAL LINKAGE
SPEED SENSOR
−
+
+
ERROR SIGNAL
INTEGRAL ELEMENT
ELECTRONIC HYDRAULIC CONTROLLER
HYDRAULIC AMPLIFIER
TURBINE SERVOMOTOR
TURBINE WICKET GATES
SUMMING JUNCTION
SERVOMOTOR POSITION SIGNAL
GENERATOR
SPEED REGULATION
10%
0
DERIVATIVE ELEMENT
WATT TRANS-DUCER
SERVOMOTOR POSITION FEEDBACK (OPTIONAL)

ELEMENTARY ELECTRONIC HYDRAULIC GOVERNOR SCHEMATIC
Figure 1

The schematic diagram of an electric hydraulic governor is shown in Figure 1. A speed signal is developed by an encoder or tach generator connected to the generator's shaft which is fed into a summing junction. At this point a speed reference signal is compared to the actual generator's speed. If the speed reference signal differs from the speed sensor signal an error signal is developed. A generator speed signal which is larger than the speed reference signal causes a positive error signal. Conversely, a smaller generator signal will cause a negative error signal. The basic equation is simply:

Speed Error = Actual Generator Speed - Speed Reference

The speed error signal is then modified by proportional, integral, and derivation (PID) actions which will calculate a gate position signal. Mathematically this is represented by the following equation:

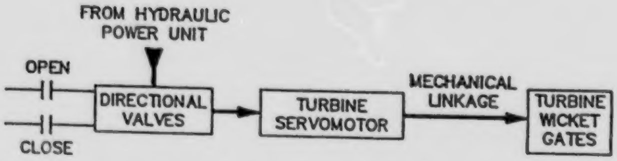
$$y = Pe + I\int e\,dt + D\frac{de}{dt}$$

Where:

y = calculated gate position signal
P = proportionality constant
e = speed error signal
I = integral proportionality constant
D = derivative proportionality constant
dt = references changes in speed error signals to time

The PID actions are necessary to provide quick and stable adjustments of the wicket gates to maintain a constant turbine speed with the least amount of over or under speed deviations during system changes (e.g. a sudden loss of load). Once a gate position value is calculated (y) the electronic to hydraulic controller will then instruct the hydraulic amplifier to provide hydraulic fluid flow to the turbine's servomotor which results in an extension or retraction of the servomotor's rod. To ensure that the servomotor actually reach the calculated position feedback is provided to the electronic hydraulic controller. The input signal to the hydraulic amplifier will be adjusted until the calculated value is the same as the actual servomotor position.

The discussion so far has only considered isochronous (constant speed) operation of the governor. In order to share loads between other paralleled units, generation feedback or speed regulation is required. This is only used if the generating unit is not responsible for frequency regulation. When the speed adjustment control is increased a speed error signal is developed. The error causes the servomotor to move the wicket gates and increase power production. The watt transducer detects the power increase and transmits a cancelling signal through the speed regulator potentiometer and a portion of that signal then enters into the summing junction. At some point the increase in generator loading will negate the speed adjustment (speed reference) increase and the servomotor will stop its movement. Therefore the governor will cause the generator to produce a constant power output regardless of fluctuations in net head. If it is desirable to maintain a constant servomotor position then speed droop or servomotor position feedback is substituted for speed regulation.



ELEMENTARY ELECTRIC HYDRAULIC POSITIONER SCHEMATIC
Figure 2

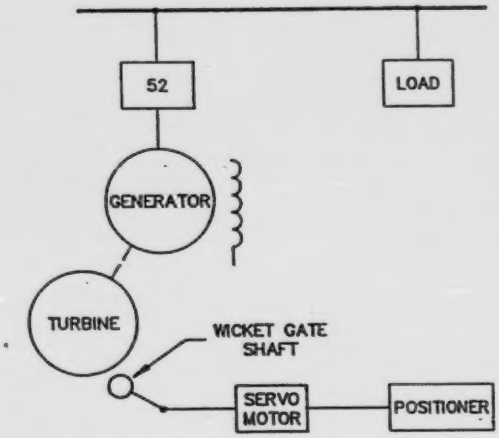
Electric hydraulic positioner as shown in Figure 2 depicts a rather simple arrangement for controlling the servomotor gate position. A contact closure activates either an open or close solenoid causing hydraulic fluid to flow to the servomotor. Thus the speed or the turbine can be adjusted during off-line conditions for synchronization and power output or load (and in some causes frequency) can be varied for on-line operations. Positioners may be as simple as a hand wheel that adjusts the wicket gate shaft or a more complicated arrangement utilizing pilot and distributing values, restoring mechanisms, and position setting cams and motor. Regardless of arrangement the positioner's only function is to set the wicket gate shaft in any desired position without regard inherently, for lack of feedback, for changes in speed or load.

The discussion of governors and positioners was only presented in an elementary form to aid the reader in understanding the following case studies.

Case Studies

Introductions

In order to gain an understanding in the application of governors and positioners various case studies will be examined starting with the isolated to infinite bus generation arrangements. The intent is to reveal the facts and fictions about what is necessary for speed and load control in small hydro applications. One may also find the discussion to be relevant with other prime movers.



CASE STUDY No. 1
POSITIONER ISOLATED CONDITION
Figure 3

Case Study No. 1: Positioner controlling a load isolated from a utility grid or other sources of power with a synchronous generator.

Initially we will adjust the positioner to rated speed (say 300 rpm) in an off line or a non-load connected condition. As long as our effective head remains constant so will the speed or our turbine. If a current is applied to the generator's field a voltage will be developed at the generator's stator terminals. We will adjust the field current so that the generator's output voltage is at rated voltage (say 480 volts). A small load is then applied to the generator's stator terminals, this is in the form of resistive heaters. Two things will begin to happen, the turbine's speed will decrease due to the stator current increase which cause a magnetic field in the stator. Imagine first a magnet being pushed across a table with a fixed force. The only force required to push the magnet is that necessary to overcome the friction of the magnet against the table therefore it will move a constant speed. If another magnet is fixed to the table in close proximity to the path of the magnet being pushed, (assume it is being pushed with the same force), the moving magnet as it passes by the fixed magnet will slow down because it has to break free of an opposing magnetic force. The stronger either of the magnets become, the slower the speed of the moving magnet will be. This analogy illustrates how the applied load to the generator causes its speed to decrease. The second event is that the generator's output voltage will drop slightly due to the reactance of the generator being in series with the load impedance. This voltage drop is further aggravated by the decrease in generator speed causing the voltage to drop even more.

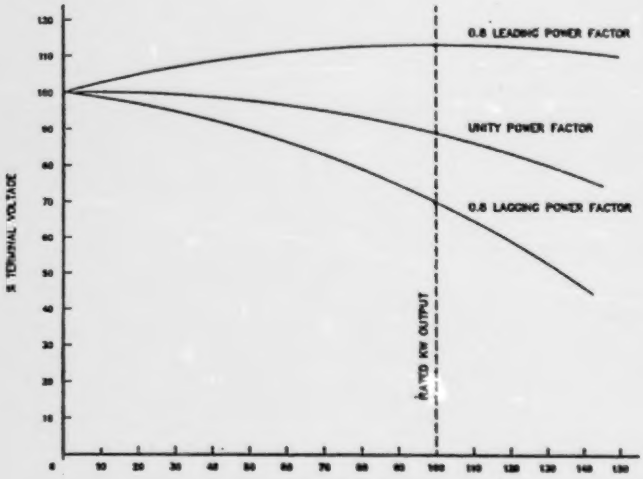
It is important to note that power is not a function of the speed in which the generator is rotating if the generator's output voltage remains constant. Therefore, a generator rotating at 250 rpm will produce the same power as the same generator rotating at 300 rpm as long as the field current is adjusted so the generator output voltage is constant. There are of course certain practical limitations in operating a turbine-generator faster or slower than its rated speed. Some of those being mechanical integrity, loss in turbine efficiency and increased generator losses (i.e. eddy currents) resulting in excessive stator heating by operating at a faster than rated speed. Operations at slower than rated speed will cause the rotor (field poles) to exceed its thermal limit and/or go into saturation causing insulation breakdown or the inability to maintain a constant voltage regardless of the field current applied. It is therefore suggested that generators be operated within ± 5 to 10% of rated speed to avoid these problems.

If our generator was feeding an inductive load (i.e. motors) rather than a resistive load more complications are introduced.

Variations in generator speed will effect the speed of motor load by the equation:

$$\text{RPM} = \frac{\text{Frequency X 120}}{\text{Number of Poles}}$$

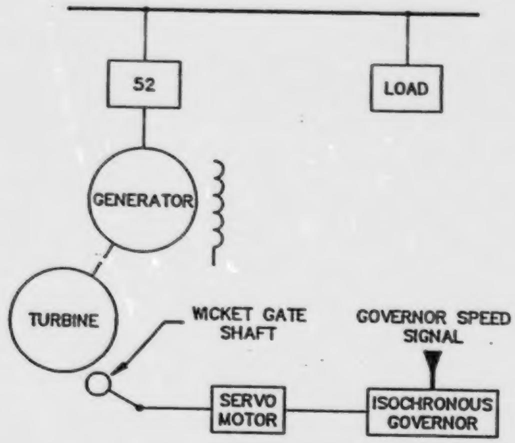
Hence the work produced by the motor(s) are related to speed (some as much as the speed cubed). Motors are also designed with a constant volts/hertz ratio, therefore voltage should be adjusted accordingly to avoid overheating. Lastly inductive loads require more field current due to a variation in flux patterns in the generator with specific load types. Figure 4 represents typical voltage vs. KW output characteristics of a generator with various load types.



TYPICAL VOLTAGE VS. KILOWATT OUTPUT CHARACTERISTICS
OF A GENERATOR AT DIFFERENT POWER FACTORS
Figure 4

In order to simplify this discussion a voltage regulator will be used to maintain a fixed generator output voltage.

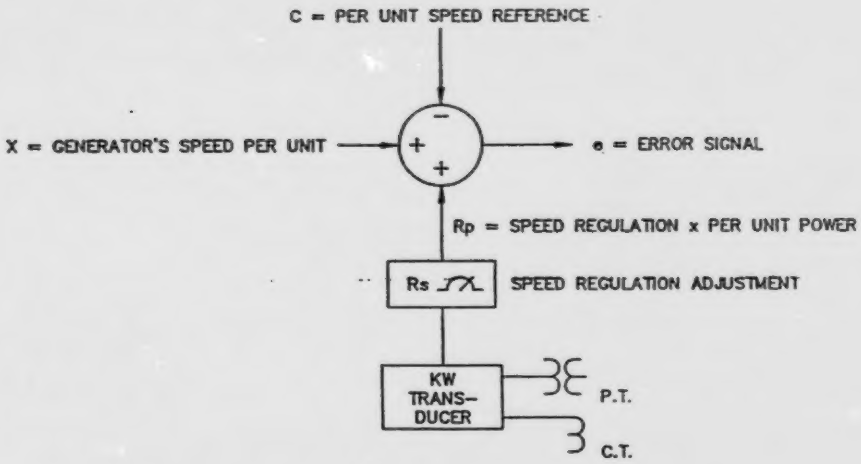
It becomes apparent that a positioner is not a good choice in controlling the turbine's speed in an isolated condition, if the load or effective head is subjected to variations.


52
LOAD
GENERATOR
TURBINE
WICKET GATE SHAFT
GOVERNOR SPEED SIGNAL
SERVO MOTOR
ISOCHRONOUS GOVERNOR

CASE STUDY No. 2
GOVERNOR ISOLATED CONDITION
Figure 5

Case Study No. 2: Governor controlling a load isolated from the utility grid with a synchronous generator.

In this particular case an isochronous governor (a governor that is capable of maintaining nearly constant turbine speed from no load to rated load) should be applied. This type of governor has only two points into its summing junction, that is of actual speed and reference speed. As the load varies the servomotor will move in a direction causing the speed error to become zero. If the load applied to the generator caused the servomotor to move to its full open position, any additional load would result in a drop in speed and frequency.


C = PER UNIT SPEED REFERENCE
−
X = GENERATOR'S SPEED PER UNIT
+
+
e = ERROR SIGNAL
Rp = SPEED REGULATION x PER UNIT POWER
Rs
SPEED REGULATION ADJUSTMENT
KW TRANS- DUCER
P.T.
C.T.

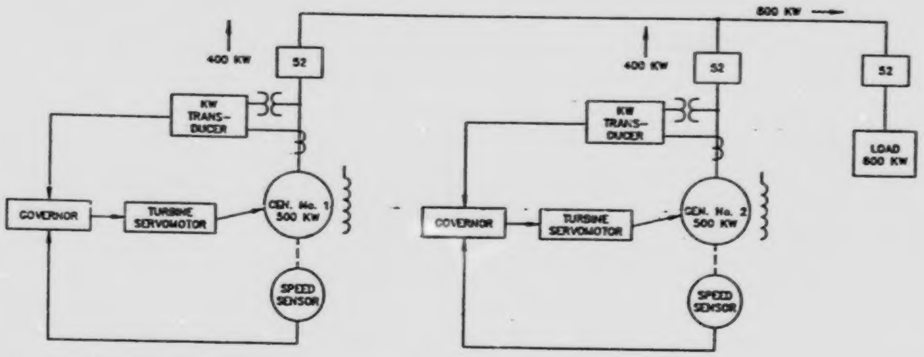
THE EQUATION REPRESENTING THE ABOVE DIAGRAM

$$e = -K(X - C + Rp)$$

THEREFORE AN INCREASE IN UNIT POWER (p) RESULTS IN A DECREASE IN PER UNIT SPEED (X) TO BRING THE ERROR (e) TO ZERO.

Figure 6

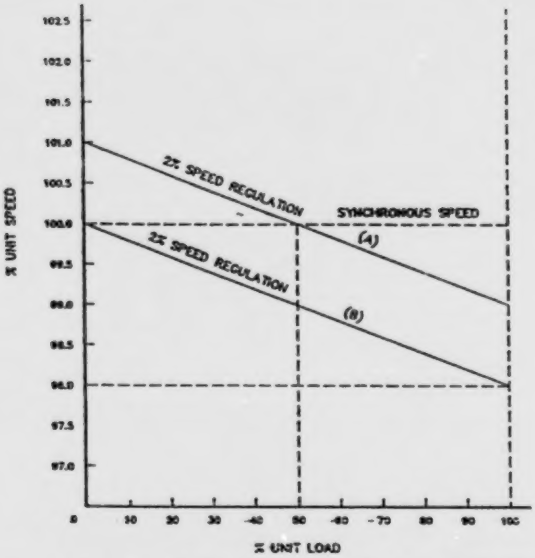
Generally speed regulation or speed droop is not used on an isolated single generator system. The introduction of any speed regulation or speed droop will cause the generator's speed to be lowered in proportion to the load applied. Let us assume we adjust the speed regulation potentiometer from zero to a value above zero. If no load is applied the governor will regulate to rated speed. The instant load is applied a signal is developed in the KW transducer. A portion of that signal is fed to the summing junction. This signal cause an immediate error signal. The wicket gates begin to close reducing the generator's speed to a point that is proportional to speed regulation times the per unit power. Figure 6 is used to explain this operation.


800 KW
400 KW
52
KW TRANS-DUCER
GOVERNOR
TURBINE SERVOMOTOR
GEN. No. 1 500 KW
SPEED SENSOR
400 KW
52
KW TRANS-DUCER
GOVERNOR
TURBINE SERVOMOTOR
GEN. No. 2 500 KW
SPEED SENSOR
52
LOAD 800 KW

CASE STUDY No. 3
MULTIPLE GOVERNOR CONTROL ISOLATED OPERATION
Figure 7

Case Study No. 3: Multiple governors controlling a load isolated from the utility grid with synchronous generators.

Case Studies 1 and 2 where relatively simple examples of load and speed control. When generators are paralleled a new set of circumstances are introduced. No longer is maintaining speed the sole criterion, but sharing of load is also necessary and becomes the major concern.



RELATIONSHIP BETWEEN UNIT SPEED AND UNIT LOADING ON AN ISOLATED 2% SPEED REGULATED GOVERNOR

(A) UNIT SPEED SET @ 101% NO LOAD, THE FULL LOAD SPEED WILL DROP TO 99% OF SYNCHRONOUS SPEED, AND SYNCHRONOUS SPEED WILL BE ACHIEVED @ 50% UNIT LOAD.

(B) UNIT SPEED SET @ 100% NO LOAD, THE FULL LOAD SPEED WILL DROP TO 98% OF SYNCHRONOUS SPEED.

Figure 8

There are two adjustments on the governor that will determine system speed or frequency and the division of load. They are the percent speed adjustment and percent speed regulation controls. The speed adjustment control sets the unit no load speed and the speed regulation control determines the amount of speed reduction that will occur based on the applied load. These controls are interactive in that on a speed versus load plot the speed adjustment determines the span and the speed regulation defines the slope of the unit speed/load characteristic line. It is important to remember that on paralleled generators different speed adjustment will not actually change the speed of each generator since they are synchronized, but how the load will be divided. The following example will elaborate on this concept. Suppose that we have a system as shown in Figure 7. Both generators are rated at 500 KW and are feeding a 800 KW load. The desired operation is to share load and maintain rated frequency. The configured system must operate in a speed regulating mode. In order for each generator to share the 800 KW load equally the speed adjustment and speed regulation controls must be set for the same value on each governor. If 2% speed regulation is chosen the speed adjustment must be set for 1.6% above rated speed. This is because if the governor speed adjustment was set at 100% of rated speed the speed would drop to 98% of rated speed with 500 KW applied. In our example 400 KW will be required from each generator or (400KW/500KW = .8) 80% of full load. Therefore to maintain rated speed at 80% of full load. Therefore to maintain rated speed at 80% loading the speed adjustment is set for 2% speed regulation X .80 load = 1.6% for each generator. A general set of equations representing the load division of these two units are:

$$P_1 = \frac{(C_1-1)}{(C_1-1)+(C_2-1)(R_{s2}/R_{s1})} \times \frac{P_{r1}}{P_{r2}} \times P_L$$

$$P_2 = \frac{(C_2-1)}{(C_2-1)+(C_1-1)(R_{s1}/R_{s2})} \times \frac{P_{r2}}{P_{r1}} \times P_L$$

Where:

C = unit speed adjustment in percent above rated speed
Rs = unit speed regulation in percent
Pr = unit rated power output in kilowatts
PL = power required by load in kilowatts
P = generator output in watts

In solving these equations the following results are obtained:

$$P_1 = \frac{(1.6-1)}{(1.6-1)+(1.6-1)(2/2)} \times \frac{500}{500} \times 800 \text{ KW} = 400 \text{ KW}$$

$$P_2 = \frac{(1.6-1)}{(1.6-1)+(1.6-1)(2/2)} \times \frac{500}{500} \times 800 \text{ KW} = 400 \text{ KW}$$

The governor settings therefore accomplish our goal of maintaining frequency and equal load division between the two generators.

By adjusting the speed adjustment of Generator No. 1 to 2%, this unit would increase its output to 500 KW, as shown by the following:

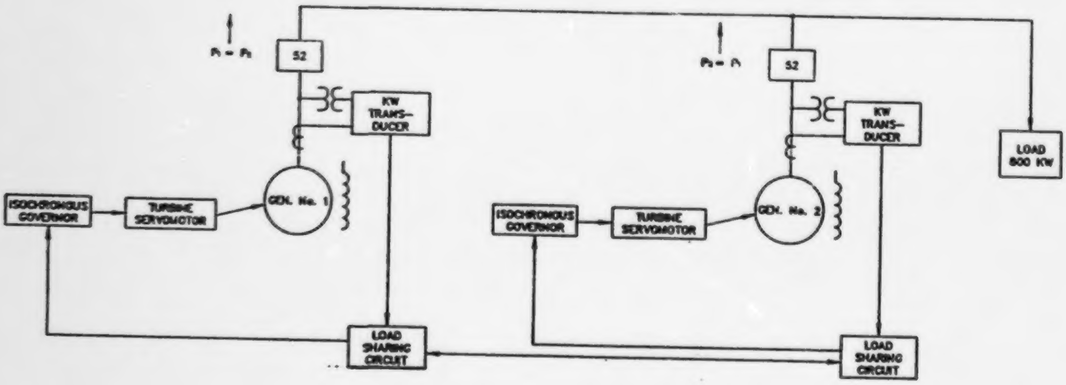
$$P_1 = \frac{(2-1)}{(2-1)+(1.6-1)(2/2)} \times \frac{500}{500} \times 800 \text{ KW} = 500 \text{ KW}$$

$$P_2 = \frac{(1.6-1)}{(1.6-1)+(2-1)(2/2)} \times \frac{500}{500} \times 800 \text{ KW} = 300 \text{ KW}$$

Generator No. 2 would automatically back down to 300 KW. What we have accomplished by this adjustment is limited the power output of the generation system to 800 KW because Generator No. 1 is at rated output and any additional load would overload this unit. Any differences in speed regulation of each governor will also cause the load to be divided unequally and limit total generation.

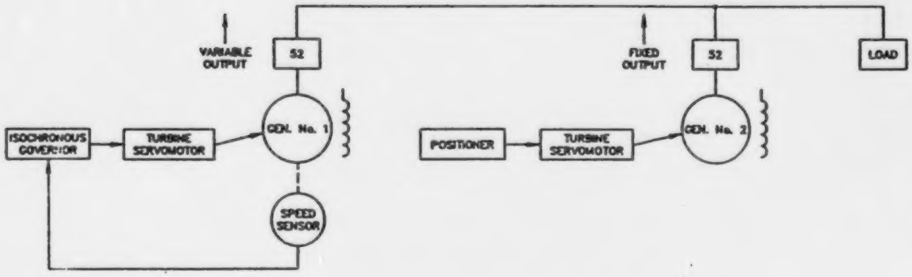
It becomes apparent that it is most desirable to set both the speed adjustments and speed regulations to the same values. The problem with this arrangement is that whenever the load changes the frequency (speed) will vary. The amount of frequency variation is usually small and periodic adjustment of the speed adjustment control will result in a good average of frequency regulation.

The question then arises, "Why not set both governors for isochronous control?" The answer to the question is that if both units are responsible for only speed control load sharing will not take place. Suppose that we were able to place on line two isochronous generators and have them divide the load equally. A sudden load is applied, since no two generating systems are identical, one will respond faster than the other and pick up the additional load. Eventually one unit will be supplying all the power to the load and quite possibly motorize the other generator. Practically speaking it would be very difficult to have any two or more generators on isochronous control load share. A speed setting, regardless of magnitude, greater than synchronous speed would fully open the wicket gates. Conversely, a speed setting less than synchronous speed would fully close the wicket gates. A multiple isolated isochronous generating system would responds in the same fashion as an isochronous generator paralleled to an infinite bus.


P1 = P1
52
KW TRANS-DUCER
ISOCHRONOUS GOVERNOR
TURBINE SERVOMOTOR
GEN. No. 1
LOAD SHARING CIRCUIT
P2 = P1
52
KW TRANS-DUCER
ISOCHRONOUS GOVERNOR
TURBINE SERVOMOTOR
GEN. No. 2
LOAD SHARING CIRCUIT
LOAD 800 KW

ISOCHRONOUS LOAD SHARING SCHEMATIC
Figure 9

Figure 9 depicts a multiple governor scheme in which isochronous load sharing can be accomplished. This is achieved by developing a KW signal in proportion to the per unit output of each generator. The signals are cross connected to form a load loop. If one generator starts taking on more load its KW signal will increase causing each of the other governors to have a positive error develop at its summing junction. This error causes the generators to equally proportion its load to the total load of the system. Therefore automatic load sharing is accomplished by balancing load signals and frequency is kept constant.

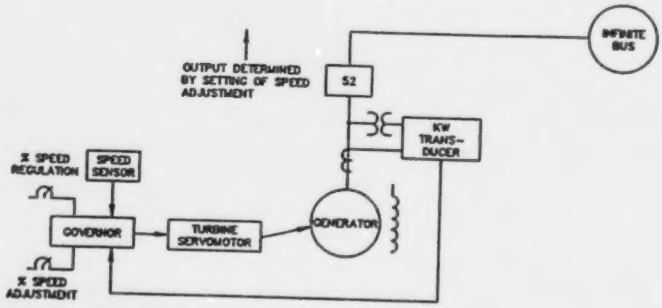

VARIABLE OUTPUT
52
FIXED OUTPUT
52
LOAD
ISOCHRONOUS GOVERNOR
TURBINE SERVOMOTOR
GEN. No. 1
SPEED SENSOR
POSITIONER
TURBINE SERVOMOTOR
GEN. No. 2

CASE STUDY No. 4
GOVERNOR – POSITIONER COMBINATION CONTROL ISOLATED OPERATION
Figure 10

Case Study No. 4: Positioner and governor controlling a load isolated from the utility with synchronous generators.

This control philosophy allows the governor, which should be set for isochronous control (zero speed regulation), to regulate a constant frequency and the positioner to divide load responsibilities. For example, a 1000 KW rated governed unit is paralleled to a 1000 KW rated positioned or gate limit unit and they are feeding a 1000 KW load. The positioner is set at a wicket gate opening producing 500 KW or 1/2 per unit output. The governor will automatically adjust its generators output to 500 KW to maintain a constant preset frequency. If the load is increased to 1500 KW the positioned unit will still be producing 500 KW, assuming the effective net head remains constant, and the governed unit will fully load to 1000 KW. Increases in load from this point will cause the governed unit to overload and frequency regulation will be lost. A reduction in load to a point less than 500 KW will result in the governed unit being motorized.

In practice one should adjust the positioner such that it is supplying approximately half of the load so that it can be left unattended, and the extremes mentioned above can be avoided. Multiple positioners can be paralleled to an isochronous governed unit. As the number of kilowatts produced by the positioned units increase verses the kilowatts produced by the governed unit the less effect the governor will have on system frequency. It is interesting to note that the larger this type of system becomes the more predominate load regulation becomes than frequency regulation, since the governed unit will have an insignificant effect on frequency regulation and can be eventually eliminated. Of course this type of system could not be left unattended for frequency would roam vastly and load management must be incorporated to sustain this system in operation. The stored energy in the rotating machines will dampen small load swings allowing time for adjustments in generation levels. Frequency feedback could than also be incorporated to vary generation of all positioned or load managed generators to maintain a near constant average frequency.

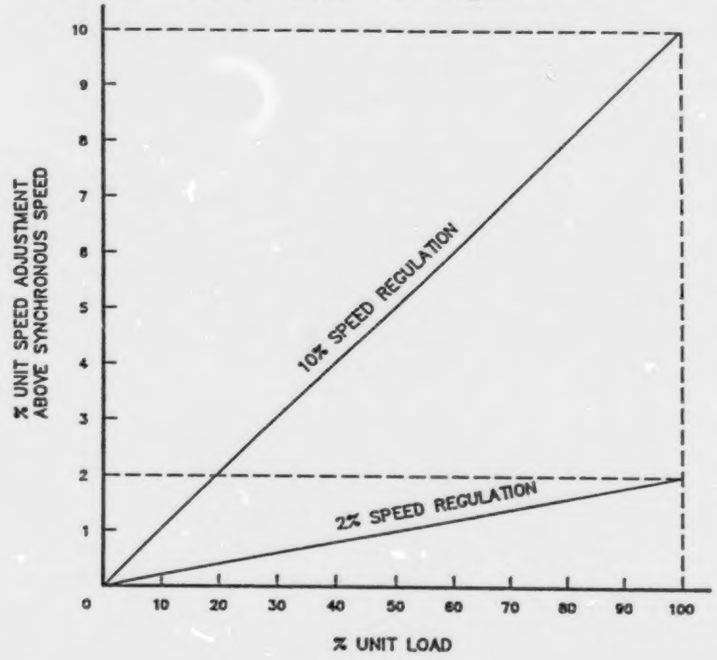

INFINITE BUS
OUTPUT DETERMINED BY SETTING OF SPEED ADJUSTMENT
52
KW TRANS-DUCER
% SPEED REGULATION
SPEED SENSOR
GOVERNOR
TURBINE SERVOMOTOR
GENERATOR
% SPEED ADJUSTMENT

100% LOADING IS ACHIEVED WHEN
% SPEED REGULATION = % SPEED ADJUSTMENT

CASE STUDY No. 5
GOVERNOR APPLIED TO AN INFINITE BUS
Figure 11

Case Study No. 5: Governor controlling a synchronous generator on an infinite bus.

When a governed unit is paralleled to an infinite bus it can not change system frequency. Therefore any attempt to increase speed or frequency will cause the governor to advance the wicket gates to the full open position and maximum output will be obtained. If the governed unit tries to lower system frequency the wicket gates will fully close and the generator will motorize. Hence, speed regulation or droop must be used to control the amount of loading on any governed unit paralleled to an infinite bus or large system. Speed regulation is illustrated in Figure 12.

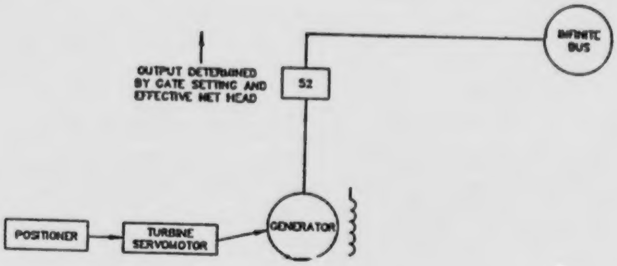


RELATIONSHIP BETWEEN UNIT LOADING AND SPEED ADJUSTMENT ON AN INFINITE BUS SYSTEM
Figure 12

The speed adjustment and speed regulation controls are interactive. When the percent speed adjustment equals percent speed regulation full unit loading is achieved. Every 1% increase in speed adjustment on a 10% speed regulated governor result in a 10% change in generator loading. The lower the value of speed regulation the greater effect the speed adjustment control has on generation. Most governor paralleled to an infinite bus use values of 4% or greater in speed regulation. This allows for finer adjustment of generator output.

The governor is still sensitive to system frequency variations. If the frequency drops outside the dead band limits of the governor a change in generation will occur to offset the mismatch of total system generator to total load. Only while frequency is changing is there a mismatch between generation and load and the system is restored when the frequency comes to a steady value even though it is other than the system normal frequency (e.g. 60 or 50 Hz). Very large systems typically have moment to moment frequency deviations of approximately 0.01 to 0.02 Hz. The higher the governor's speed regulation value, the less effect frequency variations will have on unit generation. As prime movers are considered, hydro turbines are relatively slow responding, therefore the more responsive prime movers have a greater contribution to frequency regulation.

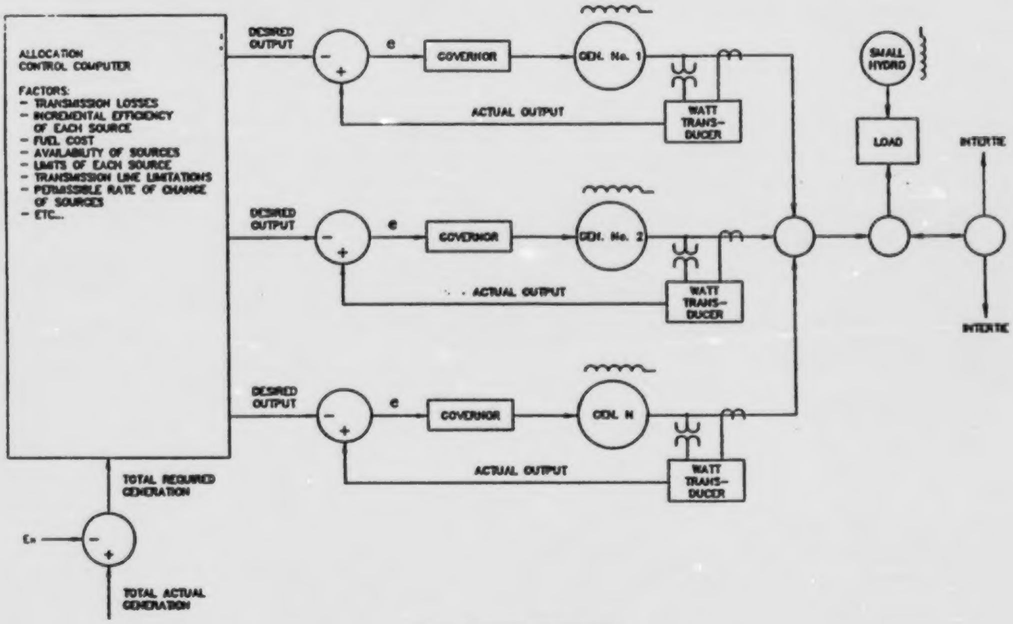
Many owners of small hydro-generation facilities are concerned with maximizing the revenue per available water flow. This equates to operating the turbine at the most efficient gate setting or justifying slightly higher outputs at a lesser efficiency due to peaking offset revenues. It becomes evident at this point that small hydro is basically a low contributing factor to frequency regulation.



CASE STUDY No. 6
POSITIONER APPLIED TO AN INFINITE BUS
Figure 13

Case Study No. 6: Positioner controlling synchronous generator on an infinite bus.

The application of a positioner on a large system is a cost effective means of adjusting generator loading. Positioners are also capable of synchronizing to the line bus. Through an autosynchronizer or other controller in which contact closures are available to control the extension or retraction of the servomotor in reference to frequency and phase angle, synchronization is easily accomplished. The use of positioners should be restricted to applications where possible isolated operation is not required. Some facilities have incorporated a combination of governors and positioners where the remote possibility of isolated operation may exist to offset equipment cost of purchasing all governors.


ALLOCATION
CONTROL COMPUTER
FACTORS:
- TRANSMISSION LOSSES
- INCREMENTAL EFFICIENCY OF EACH SOURCE
- FUEL COST
- AVAILABILITY OF SOURCES
- LIMITS OF EACH SOURCE
- TRANSMISSION LINE LIMITATIONS
- PERMISSIBLE RATE OF CHANGE OF SOURCES
- ETC..
DESIRED OUTPUT
e
GOVERNOR
GEN. No. 1
ACTUAL OUTPUT
WATT TRANS-DUCER
DESIRED OUTPUT
e
GOVERNOR
GEN. No. 2
ACTUAL OUTPUT
WATT TRANS-DUCER
DESIRED OUTPUT
e
GOVERNOR
GEN. N
ACTUAL OUTPUT
WATT TRANS-DUCER
SMALL HYDRO
LOAD
INTERTIE
INTERTIE
TOTAL REQUIRED GENERATION
E$_R$
TOTAL ACTUAL GENERATION

UTILITY CONTROL ALLOCATION
Figure 14

The utility control allocation scheme of Figure 14 shows the significance of the small hydro generation station. The small hydro plant will effect the area load and is generally not considered in the area control scheme, usually reserved for the larger higher speed prime movers. Small hydro generating stations in a majority of incidences are not capable of supplying the local area loading in the event interruption of the tie line occurs.

The plant would then overload and trip off-line. Many utilities are requiring the small hydro plant to use 81 o/u devices (over/under frequency relays) to insure the plant is removed from the grid during abnormal conditions. Thus the requirements of governors for non-isolated small hydro facilities is not of much concern and positioners can be substituted.

The positioner operating on an infinite bus is not capable of changing system frequency as wicket gate values are changed. Variations in positioner settings will only adjust the torque applied to the generator's shaft. This torque is translated into generator loading or output power. A fixed wicket gate position will allow for constant generator output, assuming the net effective head remains constant.

Stability Considerations

Stability of the generating unit especially operating isolated should be of prime importance. Regardless of how sophisticated the governor is, poor total system design will cause hunting even under nearly constant load conditions. Good speed regulation can be achieved by having the proper flywheel constant (C).

$$C = \frac{N^2 \, Wr^2}{P}$$

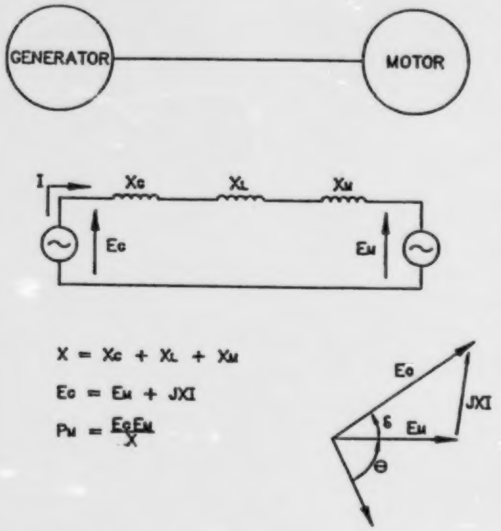
Where:

N = normal speed of unit in rpm
Wr^2 = weight of the rotating parts multiplied by the square of the radius of gyration
P = rated horsepower of unit

Values of C less than 3,000,000 will generally cause speed regulation problems. For Kaplan and fixed propelled turbines values of C greater than 5,000,000 are normally required. The smaller the hydro unit's generating capacity the more likely additional Wr^2 will be necessary.

Another interesting factor in system stability is the maximum power that can be transmitted from a generator to a load and still maintain synchronism.

POWER SYSTEM STABILITY



$X = X_G + X_L + X_M$

$E_G = E_M + JXI$

$P_M = \frac{E_G E_M}{X}$

WHERE:
X = SYSTEM REACTANCE
E_G = GENERATOR VOLTAGE
E_M = MOTOR VOLTAGE
P_M = MAXIMUM POWER TRANSMISSION (STEADY STATE)
δ = POWER ANGLE (${P_M}$ OCCURS WHEN $\delta = 90°$)

Figure 15

The example shown in Figure 15 illustrates a simple two machine power system. The angle between the generator voltage and motor voltage is called the power angle. A simple way of actually seeing the power angle is to place a fluorescent lamp (connect to the same bus as the generator) near the generator's rotating field. At a no load condition and unity power factor a pole of the rotator will line up with a corresponding stator coil. As load is applied the pole will move away from the referenced stator coil. The direction of movement will be the same as the normal units rotation. If the excitation level is increased the displacement angle will become smaller. The steady state stability limit is when the power angle is at 90 degrees. The transient stability limit is always less than the steady state stability limit and is dependent on the nature and magnitude of the disturbance.

Conclusion

There are many considerations that must be addressed in the selection of a turbine control means. This paper has dealt with the more recent developments of governor/positioner controls, in which many more control strategies are possible than what was presented. The small hydro facility can take advantage of less costly equipment in some cases so that funding a renovation or new construction is economically feasible.

References

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2. Power System Stability Volume I, Edward Kimbark, John Wiley & Sons, Inc., New York 1948

Automatic Control Systems for Small Hydro

By
J.M. Bogert

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SMALL HYDRO '88

AUTOMATIC CONTROL SYSTEMS FOR SMALL HYDRO

John M. Bogert, P.E.

The subject of this paper is automatic control systems and the benefit that is derived both technically and economically for small hydroelectric plants through the inclusion of such a system. This paper is not intended to present a technical discussion of an automatic control system, but rather, an overview of some of the concerns and issues raised by the subject. During the specification stage of a hydroelectic project, there is often a discussion between the owner, the engineer, and the operator that concerns the extent of automation that will be included in the control system.

In the past the discussion ranged from purely manual control to the definition of some degree of automatic control. Recently, the conversation has evolved to generally accept the inclusion of automatic operation, and the question has now turned to a determination of the extent of automation that will be included.

The importance of the control system in terms of the project as a whole is tremendous. There are several criteria that can be put forth that assist in describing the role that the control system plays in the overall plant:

> **PLANT RELIABILITY** is perhaps the first question addressed when evaluating a control system. From this we determine the degree of automation that all are comfortable with and the amount of confidence that can be established in the system as a whole. The turbine, generator, hydraulic systems, and powerhouse conditions must be constantly monitored to detect a fault condition or the **potential** for a fault condition, and the appropriate actions must be taken either manually or automatically.
>
> **RESOURCE OPTIMIZATION** as well as optimizing the use of the equipment in terms of preventing mechanical degradation is a primary function of the control system. How this is accomplished throughout the life of the plant in a consistent manner depends on the control system design and specification.

and the last point, related to the first two....

> **ECONOMICS** relates to the percentage of time that the unit is available and the degree of efficiency with which the resource and the equipment are utilized. These factors convert directly to increased revenue over the life of the plant.

The control system must monitor, control, protect, and communicate. The consistent performance of these functions are critical to reliability and economics of the plant.

PROTECTIVE FUNCTION includes all the relays and devices that detect a malfunction of a serious nature that **is in progress** and then act **directly** to bring the unit or the entire plant to a safe deenergized condition. The sequence by which the unit is brought to a safe state depends on the type of fault which dictates whether the unit should be shut down, first electrically, thus allowing overspeed in a load reject condition, or whether it should be unloaded first hydraulically, then disconnected electrically.

The Protective function can be subdivided into three main areas:

> *Electrical relaying (which remains independent of the PLC), frequency, voltage, overcurrent, negative sequence detection, etc.
>
> *Mechanical Relaying - bearing overtemp, excessive vibration, auxiliary system pressures and flows, etc.
>
> *Station Protection - tie line monitoring, power transformer, powerhouse conditions, fire detection, intrusion, etc.

FAULT ANTICIPATION could be considered the automatic enhancement to the control system. The term implies that faults will be anticipated before they occur and the conditions that caused them identified such that the fault never occurs.

An automatic system is the only cost effective way to implement such a function. Through the collection of operational data and the comparison of this data with baseline conditions that were established during commissioning or under controlled conditions, the automatic system is able to anticipate the degradation of equipment or subsystems.

By way of illustration, we might look at a typical Kaplan unit that automatically controls the gate, blade, and head relationship. By recording the flow and power at a number of points on the 3-D cam and storing them in the controller, the system can constantly monitor the performance of a unit through comparison with the results of the index test done during commissioning. By alerting the operator (either remotely or locally) to a potential problem, the system can continue to operate while additional troubleshooting is accomplished.

Similarly, baseline data relating to pressures, flows, and timings of hydraulic subsystems can be compared to the operating data. Conditions that would cause faults if left unattended can be detected and operating revenue gained through the anticipation of irregular situations.

CONTROL FUNCTION

The types of turbine and generator control that can be implemented through the control system are numerous. The extent of the algorithms are actually limited only by the input signals or preprogrammed information that is available for processing. Some of the possibilities for control are level control, penstock pressure control, flow control, or efficiency optimization. All of these algorithms can be implemented depending on the extent of the inputs available.

In addition, the control system must supervise multiple unit starting and sequencing, release schedules and environmental requirements, and revenue optimization in the form of peaking schedules and utilization of impoundment.

COMMUNICATIONS

The integrated automatic plant will communicate with the outside world directly. Either reporting, control, or a full data acquisition system should be specified to be incorporated in the automatic device that is in the plant. A stand alone RTU for reporting is an unnecessary expense and should be avoided.

The importance of the communication aspect of the automatic system should not be underrated. Information relating to the operation of the plant and to the utilization of the resource is valuable data in assessing the revenue producing capabilities of the facility. Assumptions as to operation in unusual or questionable generation periods can be quickly verified or, in most cases, corrected.

Some specific issues that have been encountered, some resolved and some not, during the past ten years of small hydro development in the US include the following:

*The requirement for a manual control panel operating in parallel with the automatic system...

*The requirement for frequency governing...

*Interaction between operator/maintenance personnel and the control system...

MANUAL CONTROL

Full manual control implies that a fully trained, knowledgeable operator will have complete control of the plant in terms of the starting and stopping of auxiliaries, synchronizing, loading, resource optimization , etc. In addition, and perhaps one of the most important functions of an operator in a manually controlled plant, is the timely recognition of faults or malfunctions and the maintenance of equipment in order to minimize or prevent damage.

The automatic system performs the monitoring and control function in a predictable and reliable manner, thus permitting the operator to devote more time to plant and system maintenance. The question then becomes, "What degree of manual control should be incorporated in the system?"

It is suggested that the investment in manual controls be evaluated in the context of emergency revenue generation only. This implies that the manual control board will be utilized a small percentage of the time and should be designed as such. Two alternatives have been used frequently and are termed "maintenance mode" and "semi-automatic mode".

The former incorporates a full complement of manual controls and meters that are totally independent of the programmable controller (PLC), but are used only for initial startup and for maintenance procedures. This specification permits the manual system to be simplified in terms of hardwired interlocks and keys the operator to proceed in a cautious, deliberate manner.

A semi automatic mode will incorporate the PLC to supervise the critical functions of the machine, including synchronizing and pre-start interlocks, but will permit an operator, for example, to load the machine, adjust the 3-D cam relationship (if applicable), or initiate a shutdown.

The benefit for each mode is that the machine is operated in a consistent manner and the knowledge of the critical parameters resides with the unit rather than the operators. The manual controls will permit the machine to be operated in the event of a failure of the primary system, but will encourage the rapid repair of that system to return the machine to it's most efficient operating condition.

FREQUENCY GOVERNING

Frequency governing must be incorporated in the design of a small hydro plant if that plant is to operate in an isolated situation not connected to the utility system or a similar "stiff" system. In almost all other situations a PID controlled gate (also needle or blade) positioning is entirely appropriate.

The purpose of the small hydro plant in almost all instances is to generate revenue through the optimal use of the resource. Frequency governing is inconsistent with this purpose. Head water level control, flow control, peaking schedules are all incompatible with a system whose primary purpose is to control frequency.

The additional costs to include a true frequency governor in a small hydro system extend beyond the initial investment in the governor. The inertial mass of the turbine/governor set must be evaluated in conjunction with the water starting time and the predicted load change. If the mass of the unit must be increased to accommodate governing, the costs associated with equipment, civil costs, and installation are likely to be affected.

The interconnecting Utility must be consulted for their policy on standalone generation connected to their system. In most cases, Utilities require that all generation must be **visibly** disconnected from the line in the event that the utility is down. In situations where there is little or no local load, the plant would shut down due to minimum loading.

Considering the marginal frequency control available with small hydro, the fact that the owner does not receive revenue from the Utility for frequency control and the minimal effect that a small plant will have on the Utility system, the inclusion of a frequency governor is not economically justified. The automatic control system, through the PLC, will perform the control functions necessary to maximize machine utilization and revenue through a closed loop system.

MAINTENANCE

The automatic control system provides an excellent means of prompting maintenance procedures and for anticipating service on systems between scheduled outages. The information gathering and storage capability of microprocessor based control systems enables the use of the PLC as a scheduler and operator log to facilitate and verify maintenance.

A program that is gaining acceptance at present is the incorporation of an expert system in a peripheral computer that receives machine data from the PLC. The expert system is able to store in an organized manner all the "expert" knowledge that is entered concerning the particular characteristics of the machine and plant. Upon a query from an operator relating to a fault condition or irregular occurrence, the expert system is able to infer a solution or a recommended course of action.

Using the expert system, an owner is able to accumulate knowledge about the plant and apply it consistently throughout the 50 year design life of the facility.

CONCLUSION

The benefits that can be derived from the incorporation of a well designed automatic control system in a small hydro generating facility all center around the acquisition of information. It is the consistent gathering of information about the environment and the machine that enable the processing that results in greater revenue and increased plant availability.

Electrical Protection, Monitoring and Control Systems for Small Water-To-Wire Hydro Electric Power Plants

By
W. Krohn, C. Mercier

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Electrical Protection, Monitoring and Control Systems for Small Water-to-Wire Hydro Electric Power Plants.

WERNER KROHN * , CLAUDE MERCIER **

Abstract:

Small Hydro Electric Power Plants are usually rated between 1 and 10 megawatts. For this size of plant the water-to-wire contract approach is normally the best suited. It focuses responsibility for design, procurement, coordination, installation and commissioning on one organization. This approach assures that efforts are directed at resolving problems as they arise without having to involve other contractors.

Protection of equipment, status monitoring and controls for optimum water usage are important factors when designing the power plant.

This paper discusses requirements for design and application of Power Plant equipment such as Generator, Excitation, Electronic/Hydraulic Governor, Switchgear, CM & R (Control, Metering and Relay) panels including PLC, Station Service System, DC System, Substation equipment and Interconnection Wiring. It also discusses the coordination study and setting of protective relays as well as principles and configurations of different control modes.

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1.0 GENERAL:

Figure 1 shows a typical single line diagram for a Hydroelectric generating station, in this case Port Dalhousie, which is rated at 3375 KW output per generator. For reasons of clarity only one of the two identical generator circuits is shown.

This figure depicts the two major electrical systems and how they interrelate. The high voltage system is indicated by a heavy outline and the low voltage and control system by a light outline. This single line diagram will differ from project to project depending on customer and public utility requirements.

Figure 2 is a simplification of figure 1 showing major electrical items in block diagram form. It should be noted that the protective relays, although shown as part of the control panels, may also be mounted on the switchgear panels.

2.0 GENERATOR

2.1 General

The generator converts the mechanical power produced by the turbine into electrical power. The two major components of the generator are the rotor and the stator. The rotor is the rotating assembly, which is attached by a connecting shaft to the turbine, either directly or through a speed increaser. The stator is the stationary portion of the generator. The two major electrical types of generators are briefly described below.

...3

2.2) Synchronous Generators

A synchronous generator runs at synchronous speed and is synchronized to the power system voltage, frequency and phase angle before the generator is tied into the power grid. The generator excitation is direct current (DC). Synchronous generator excitation is controlled to provide lead and lag reactive power required by the power system for power factor correction. Synchronous generators can also run isolated from the grid and produce power since excitation power is not grid-dependent.

2.3) Induction Generators

An induction generator in principal is a simple electric squirrel cage induction motor which may or may not be especially designed for generator application. It is mechanically driven at a speed higher than synchronous speed. As the shaft speed is increased, the amount of electrical power delivered by the generator also increases until the rated output is reached. The major difference between the induction and synchronous generators is that the induction generator in principal cannot generate while disconnected from the power system, because it is incapable of providing its own excitation current. Induction generators cannot correct power factor. The power factor is fixed by design parameters and changes with load.

However, it is possible to improve the power factor by adding capacitors.

Since induction generators are mainly used below 1 MW they are not within the scope of this paper and will not be discussed any further.

... 4

2.4) Parameters to consider when evaluating a synchronous generator

The generator design must be adapted to the generator's mechanical and electrical interfaces. These are on the primary side the turbine and the secondary side the electrical grid.

2.4.1) Essential parameters to be specified when ordering a generator

- Output rating
- Voltage
- Number of phases
- Frequency
- Power factor
- RPM
- Runaway speed and duration
- Service factor
- Insulation class
- Temperature rises and how measured
- Ambient temperature
- Enclosure and ventilation system
- Mounting (horizontal or vertical)
- Sound level
- Type of bearings and lubrication
- Auxiliary devices such as RTD's, C.T.'s, heaters, surge protection and neutral grounding equipment.
- Connection (star or delta)
- Additional radial and/or axial loads due to turbine
- Coupling requirements (rigid, flexible, end float)
- Inspection, factory and field tests

...5

2.4.2) **Parameters that may be specified**

- Minimum inertia
- Desired efficiencies
- Short circuit ratio
- Reactance values
- Limitations in space, installation and transportation
- Specific terminal box locations
- Brake design parameters
- Speed pick-up requirements
- Excitation system (static or brushless)

2.4.3) **Parameters defined by generator manufacturer**

- Electrical design of stator and rotor to meet essential parameters and optimize design as to performance and cost.

- Mechanical design to satisfy requirements of coupling, enclosure, ventilation, noise, bearings, foundation, installation, maintenance etc.

Close coordination is required between the prime mover (turbine) design and the generator design to arrive at the best solution possible with regard to overall efficiency and performance. This may also include a speed increaser as in the case of Port Dalhousie. Aspects that require particular attention are sufficient system inertia to minimize pressure and speed rise upon shutdown and to maintain a stable speed for synchronization and enough generator/turbine shaft stiffness for rigidly coupled machines to keep the critical speed above the off-cam runaway speed.

.../6

3.0 POWER TRANSFORMER

3.1 General

To match the generator voltage to the utility grid, a power transformer is required. In most cases these are located close to the powerhouse in the switchyard to minimize cable losses. The power transformer, as well as the generator, are critical items which have to be specified and ordered soon after contract award for a water-to-wire package because of long delivery times. To specify a power transformer, a good knowledge of the utility grid is required in order to minimize any disturbances on transmission lines, telephone interference and magnitude of third-harmonic currents. In most cases the utility will want to approve the transformer selection.

Outdoor power transformers for Small Hydro use oil as an insulating and cooling medium.

3.2 Cooling methods

Several different cooling methods are available. The most common are shown below.

COOLING METHOD	CSA DESIGNATION	ANSI DESIGNATION
Oil-Immersed, Natural Circulation, Self-Cooled	ONAN	OA
Oil-Immersed, Natural Circulation, Forced Air Cooled	ONAF	FA

Relative ratings:

ONAN - 100%
ONAF - 100%
ONAN/ONAF - 100/133%

.../7

The addition of a set of fans to a self-cooled transformer will increase the capacity to 133%.

3.3) Oil Preservation Systems

An oil preservation system is required on each transformer to reduce or eliminate sludging when the warm transformer oil is oxidized and to protect the oil from outside contaminants. Sludge reduces the unit's ability to dissipate heat, and contaminants reduce the dielectric qualities of the oil. Different types of oil preservation systems are available, each with certain advantages and disadvantages. These are:

3.3.1) Sealed tank oil preservation (transformer is sealed and air tight). The tank is designed to withstand underpressure when cold and overpressure when hot.

3.3.2) Conservator oil preservation system (the conservator is a separate tank, into which the transformer oil may flow freely as it expands or contracts due to thermal cycling)

3.3.3) Automatic positive pressure oil preservation (a regulating network maintains a positive pressure on the gas space above the oil).

.../8

3.4) Transformer Connections

Figure 3 shows a three-phase transformer bank connected between the power plant generator and the utility grid. The selection of the transformer connection is most important when specifying a power transformer. In fact, the exciting current of a transformer contains appreciable harmonic currents. The third harmonic is by far the largest harmonic component, being as high as 40 to 50 percent of the fundamental sine-wave exciting current. The exciting current will take the shape imposed by the particular connections used. It is always preferable to have at least one delta-connected winding in a three-phase transformer bank. The delta connection will furnish a internal path for the flow of third-harmonic currents and and will minimize the third-harmonic current in the external circuits. This is very desirable because third-harmonic currents in the external circuits may, under some conditions cause telephone interference or false relay tripping.

3.5) Parameters to be Specified when Ordering a Power Transformer

- Voltage ratio
- Connections
- Cooling method
- Type of oil preservation system
- Temperature rise
- Ambient temperature
- Impedance
- BIL
- Noise level
- Winding taps and tap changers (off-load or on-load)
- Winding material (copper or aluminum)
- Connection configuration (terminal box or insulators)
- Accessories such as temperature, oil level and pressure indicators, sudden pressure relay, current transformers and lightning arrestors:

.../9

4.0 SWITCHGEAR PANEL AND PROTECTION SYSTEM

4.1) General

The switchgear panel line-up typically contains the generator breaker, potential transformers (P.T.'s), current transformers (C.T.'s), a fused disconnect switch for the station service power system and the copper bus bars. Protective relays (electro-magnetic or solid state) may be mounted on the switchgear or contol panels as space permits.

In the generating station, the switchgear provides protection for the generator(s), main transformer and station service transformer. Selection of the proper switchgear for a particular generating station requires a knowledge of the functions of switchgear, system-voltage considerations, and protection and coordination. The loads that are to be supplied by the switchgear, as well as the characteristics of these loads and therefore the protection they require, must all be known.

4.2) Switchgear Specification

When the above is defined, the electrical project engineer writes a specification for the switchgear to be supplied which includes a detailed bill of material and National and International Standards applicable for the given project. Selection criteria for switchgear manufacturers include experience, reputation, price, ability and willingness to work with the turbine manufacturer. The manufacturer must also be acceptable to the Consulting Engineers (if any) and the client. Although the bill of material can be quite specific the detail design of the panels is the responsibility of the manufacurer.

.../10

The metal-clad switchgear has the following features:

- The circuit breaker is removable and can be moved into the operating, test and disconnect position.
- The primary circuit, consisting of the circuit breaker, buses, and potential transformers, is enclosed in grounded metal compartments.
- Insulating materials cover the bus conductors, and connectors.
- When the circuit breaker is removed, automatic shutters close off and prevent exposure of the live primary conductors.

4.2.1 Equipment to the specified in the switchgear are:

- circuit breaker:
  - type (air, vacuum, SF6)
  - nominal voltage
  - frequency
  - rated continuous current
  - rated short circuit
  - voltage for spring charging motor operation
  - voltage for close/trip coil
  - accessories

.../11

- Current transformer and potential transformer:
    - ratio, rating
    - accuracy classes (metering, relaying)

- PT trunnion

- Control Switches:
    - type, rating, manufacturer

- Interior lighting, outlet receptacles and heaters

- Protective relays and lockout relay

- Load break switch
    - rating
    - fuses required

- Entrance requirements for control and power cable (from top and/or bottom)

- Space requirements for stress cones.

5.0 COORDINATION STUDY AND SETTING OF PROTECTIVE RELAYS

5.1) General

When designing small power plants, it is important to provide adequate protective relaying to avoid problems with the electric grid system and generating station equipment when a fault occurs on the utility side or generating station side. The choice and setting of the protective relays are critical in order to :

- Ensure public safety and equipment protection
- Keep customer service quality
- Coordinate with utility grid
- Protect the G.S. from internal damage caused by the utility system
- Protect the grid form G.S. faults.

.../12

5.2) Evaluating Short Circuit Condition

The source of fault currents are "rotating electric machines". These are in our case:

1- Synchronous generator(s)
2- Induction Machines
3- Electric Utility System (grid)

The current from each rotating machine source is limited by the impedance of the machine and the impedance between the machine and the fault. The impedance of a rotating machine is not a simple value, but is complex and variable with time. The procedure for calculating the short-circuit consist of the following steps:

- prepare system diagram
- combine impedances
- calculate short-circuit current in different locations

5.3 Data Required for calculations:

5.3.1) **Generator:** The substransient reactance (x "d) which is used to determine the current during the first cycle after a fault occurs

5.3.2) **Transformer:** Transformer impedance expressed in percent

5.3.3) **Utility:** Highest applicable magnitude of short-circuit contribution delivered by the utility from all sources outside the generating station.

.../13

5.3.4) **Induction motors:** In our case induction motors are smaller than 30 HP and their fault contribution is negligible.

Evaluating the short circuit at different locations in the system allows to verify the rating of each generator breaker, station service breaker and power cable (bus) under these short circuit conditions.

5.4) Generator Protection

The following shows a typical protective relay list for the protection of the generator (s).

Device 51V

Voltage restraint overcurrent relay provides back-up protection by detecting external faults and tripping the generator circuit breaker in the event that downstream protective devices fail to operate.

Device 32

The reverse power relay provides protection against generator motoring. The relay operates for power flow into the generator. Motoring results from a low prime-mover input to the generator. It is recommended to have a time delay relay to prevent tripping during power swings, which may occur as a result of synchronizing or during system disturbances.

Device 40

The loss of field relay senses the change in impedance of the generator stator, which occurs upon over or under excitation, loss of field to the main exciter, accidental tripping of the field breaker, short circuits in the field windings or loss of AC supply to the excitation system. Relay setting depends on the generator capability curve.

.../14

Device 46

The negative sequence overcurrent relay provides protection against generator overheating due to unbalanced loads or faults in the system. According to NEMA standards the permissable integrated product of negative sequence current and time $(I_2)^2$ t which standard hydraulic turbine generators can tolerate is a minimum of 40.

Device 87G

The differential current relays provide protection against internal faults in the generator stator winding such as a short or ground in one or more phases. In differential protection, the currents in each phase, on each side of the winding, are compared in a differential circuit. When the difference exceeds the set value the tripping circuit is activated. It is recommended to use current transformer of equal ratio and magnetic characteristics for optimum operation.

Device 64G

The generator ground fault relay provides system back-up as well as generator ground fault protection. There are several ways of grounding synchronous generator neutrals, influenced by the choice of step-up transformer connection to accommodate system grounding and various other factors, including individual preferences. High impedance grounding using a small distribution transformer (with secondary resistor) in the generator neutral is the common method employed in small hydro.

5.5) Bus Protection

The four relays required in most three phase bus protection systems are:

Device 27 - Under voltage relay
Device 59 - Over voltage relay
Device 81O - Over frequency
Device 81U - Under frequency

.../15

The relay functions and the abnormalities detected are summarized as follows:

Over/under voltage: detect faults, prevent accidental energization of utility line.

Over/under frequency: detect islanding conditions.

Setting of these relays will depend on utility requirements.

Typical setting for frequency relay is ± 0.5 HZ

Typical setting for voltage relay is ± 10%.

5.6) Power Transformer Protection

Instantaneous overcurrent relay (device 50) and time overcurrent relay (device 51) protect the main power transformer when a fault is detected on the bus system or an internal fault in the main power transformer. A device 87T (transformer differential protection) may or may not be used depending on the transformer size. 87T functions similar to 87G.

5.7) Relay Coordination

In a generating station being part of a larger system the available short-circuit current is so great that major damage to expensive equipment can occur in split seconds. Protective relays, fuses and other trip devices are designed to remove faulted equipment from the rest of the system before major damage can take place and with minimum disturbance to the rest of the system which is not faulted. This means that the protective device closest to the faulted equipment should trip first and backup devices later in case the primary protection does not function.

.../16

Coordination consists of the selective operation of the various protective devices in such a way that the device closest to the fault operates first. This is achieved by carefully setting the protective devices with current pickups and operating times. The devices back toward the power source have progressively higher ampere pickups and longer time settings.

Coordination is most easily done by plotting the time-overcurrent characteristics of the various devices on a single sheet of log-log graph paper.

6.0 CONTROL PANELS

6.1) General

Control panels house all the metering, instrumentation, control equipment, programmable controller and electronic governor head which are vital for the safe and efficient operation of the generation station. The scope and complexity of control systems vary widely and are a function of the size and supervision of the plant, the level of option skill and the need and level of automatic and/or manual operation.

6.2) Metering

Adequate instrumentation such as voltmeters, ammeters, KW meters, wicket gate opening indicators, net head indicator , etc. are required for the operator to monitor the plant, to load his equipment properly and to trouble shoot the system. Such equipment is of the switchboard type or a video screen. When the plant has provision for manual synchronization, a synchroscope plus additional meters on the utility side or main bus are required.

.../17

6.3) Control Equipment

When not part of the programmable controller, a sync-check relay and automatic synchronizer are essential in the sequence to tie the generator to the utility grid. The sync-check relay assures proper synchronization when done manually by comparing voltage, phase angle and frequency of utility grid and generator output.

Until all of these parameters fall within preset limits the relay will not allow synchronization. Faulty synchronization could cause serious damage to the generator.

To match the generator voltage, frequency and phase angle with the utility grid, manual operation need to be performed to control the generator excitation and turbine wicket gate opening. In the automatic synchronizing mode, the same functions as in the manual mode are required to synchronize the generator except that everything is done automatically by the auto - synchronizer.

6.4) Programmable Controller

The programmable controller (PLC) provides sophisticated automation capability and increased reliability and maintainability. All control switches, temperature sensors, flow sensors, pressure sensors, level sensors, vibrations sensors, lockout relay auxiliary contacts and breaker auxiliary contacts are connected to the PLC. A significant numbers of electrical, electromechanical, mechanical and electronic components are now replaced by programs in the PLC. The use of PLC usually increases revenues and reduces operation and maintenance costs.

.../18

The following functions can be controlled with the PLC:

- Unit start sequencing (after system is normalized)
- Normal shutdown sequencing
- Emergency shutdown sequencing
- Water level control (using pressure transducers)
- Monitoring, annunciator
- Interfacing with remote monitoring and control (SCADA) via a modem.
- Interfacing with local and/or remote CRT screens, data loggers, printers.

One important feature of our approach for water-to-wire is that DBS Escher Wyss will do the PLC programming in-house. The control algorithm are developed by the equipment supplier who knows best how his equipment should be run and protected.

Figure 4 shows a simplified control block diagram.

7.0 ELECTRICAL/HYDRAULIC GOVERNOR

7.1) General

The task of the speed governor for a water turbine comprises basically a suitable conversion of the speed deviation from the reference value into a movement of the adjusting member of the controlled system or the regulating mechanism of the water turbine, respectively. The governing equipment thus incorporates a section dictating the regulating behaviour, the actual governor and one or more amplifiers. They convert the original signal from the governor into a proportional motion of the turbine regulating mechanisms.

7.2) Electronic Governor:

For the Port Dalhousie generating station, electronic modules are used for the governing of the water turbines. The governor which is of the electro-hydraulic actuator type senses the speed of the turbine rotation, generates a signal proportional to the difference between the turbine speed and the governor speed reference and therefrom develop hydraulic control signals of sufficient power to position the turbine wicket gates as required to control the pit type turbines.

.../19

The governor actuator rating is adequate to operate the turbine control servomotors in the minimum time specified, taking into account the pressure drops of piping external to the actuator.

The speed sensing element of the governor receives its speed signal from a speed pick-up located on the generator or speed increaser shaft. The signal is suitably converted by an electronic module part of the governor.

The governor block diagram in figure 5 shows the overall structure of the governor in the most comprehensive stage as needed for double-regulated Kaplan turbines. For the Port Dalhousie Propeller units the modules shown within the dotted line frame are not required. The diagram shows individual functional units (modules) as blocks in relation to the signal flow, ranging from the shaft speed (controlled variable) and the command signal setting as the input to the PID section in which the conversion of the error signal takes place, right up to the amplifiers. The supplementary devices are also included to improve the governing behaviour and transient response. During large deviations from the reference speed (starting, load rejection), the Rum 20 module will switch the integral time constant to a lower set value as a function of the error signal.

The output signal of the PID modules is fed to the electro-hydraulic amplifier. This has the task of positioning the servomotors of the turbine regulating mechanism in order to follow the governor output and thus represents an amplifier with unit feed-back.

In order to ensure optimum efficiency at each operating point, a definite exactly adjustable relationship between guide vanes (wicket gates) and runner blade positions must exist depending on the operating head.

.../20

In the electronic governing system the relationship is formed by inserting a standard function generator in the runner blade feedback. This circuitry facilitates the monitoring of the positioning of both regulating devices, since the actual value of the guide vane angle can be immediately compared with the actual value of the runner blade angle, as converted by the function generator. The find tuning of the optimum blade/gate relationship correlation curves will be performed by DBS Escher Wyss during commissioning.

When, during operation, a preset deviation has been exceeded a relay within the governor is activated, initiating a delayed warning and/or shutdown.

8.0 STATION SERVICE POWER SYSTEM

This system is normally connected to the generating line but may be, in case of generating line failure, connected to a separate line or a standby generator set. This way emergency loads such as pumps, lighting and heating will have continuous power.

The system will provide power to the motor control center (MCC) powering motors and other loads inside an outside the powerhouse and to the distribution/lighting panel.

9.0 DC SYSTEM

The DC system consists of the battery charger, the station batteries and the DC distribution panel. AC power for the charger is provided by the station service power system. The battery capacity (and also the charger size) will have to be sufficient to provide control power for relays and breakers, power to the dedicated inverter for the PLC, to the electronic governor and to DC backup pumps, if any.

.../21

10.0 OUTDOOR SUBSTATION

In some cases the water-to-wire electrical supply includes the substation or parts of it. The line breaker or circuit switcher will separate the power plant and step-up transformer from the grid in case of faults on the power plant side. The disconnect switch which is usually mounted on the dead-end structure will separate the line breaker and all other equipment towards the power plant from the grid voltage for maintenance purposes. The dead-end structure is the connecting link between the plant output conductors and the take-off lines to the grid. Lightning arrestors for protection against line surges or lightning strikes could be mounted on the transformer or the dead-end structure. P.T.'s and C.T's for revenue metering are normally mounted on the dead-end structure.

11.0 INTERCONNECTION PACKAGE

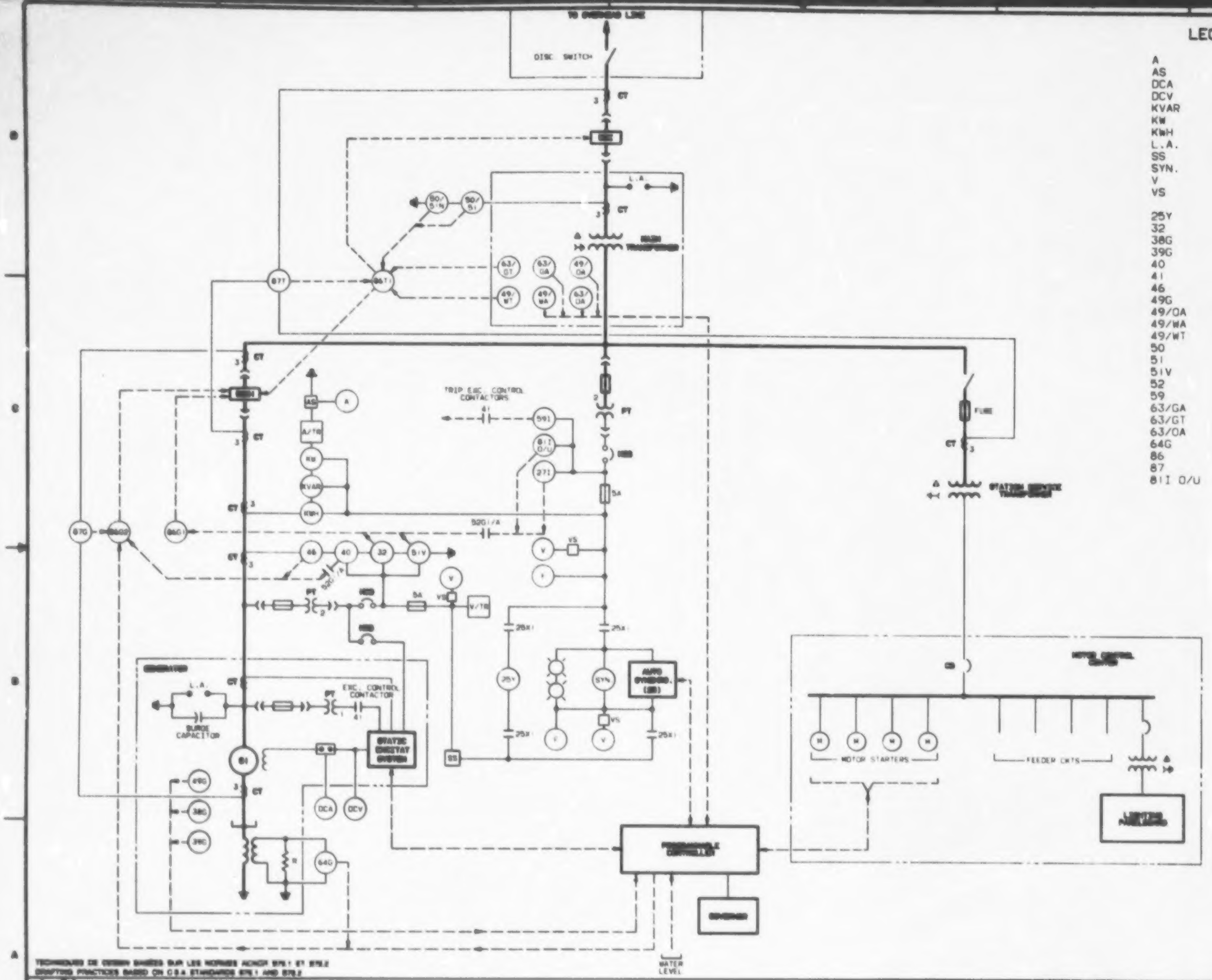
This package consists of supply and installation of conduits, cable tray, wires and cables to interconnect between DBS Escher Wyss supplied equipment. Determination of routing and sizes as well as interconnection wiring diagrams and cable lists are part of the supply.

REFERENCES:

- "Seven Years of Field Experience with Small Hydro Project in North America" P.J. Jermann, F. Mas, "Hydro '88" Cancun, Mexico.

- "The Governing of Water Turbines using Electronic Modules", W. Wuehrer, Escher-Wyss.

CM4/MS


TO OVERHEAD LINE
DISC. SWITCH
CT
L.A.
MAIN TRANSFORMER
TRIP EXC. CONTROL CONTACTORS
PT
FUSE
STATION SERVICE TRANSFORMER
GENERATOR
SURGE CAPACITOR
EXC. CONTROL CONTACTOR
STATIC EXCITAT SYSTEM
AUTO SYNCHRO.
MOTOR CONTROL CENTER
MOTOR STARTERS
FEEDER CKTS
LIGHTING PANELBOARD
PROGRAMMABLE CONTROLLER
WATER LEVEL

LEGEND

A	AMMETER
AS	AMMETER SWITCH
DCA	DC AMMETER
DCV	DC VOLTMETER
KVAR	KILO VAR METER
KW	KILOWATT METER
KWH	KILOWATT HOUR METER
L.A.	LIGHTNING ARRESTER
SS	SYNCHRONIZING SELECTOR SWITCH
SYN.	SYNCHROSCOPE
V	VOLTMETER
VS	VOLTMETER SWITCH
25Y	SYNCHRONISM CHECK RELAY
32	DIRECTIONAL POWER RELAY
38G	GENERATOR EXCESSIVE BEARING TEMP.
39G	GENERATOR EXCESSIVE VIBRATION
40	LOSS OF FIELD RELAY
41	FIELD CIRCUIT CONTACTOR
46	PHASE UNBALANCE RELAY (NEGATIVE SEQUENCE)
49G	GENERATOR EXCESSIVE WINDING TEMP.
49/OA	TRANSFORMER OIL TEMP. ALARM
49/WA	TRANSFORMER WINDING TEMP. ALARM
49/WT	TRANSFORMER WINDING TEMP. TRIP
50	INSTANTANEOUS OVERCURRENT RELAY
51	TIME OVERCURRENT RELAY
51V	VOLTAGE RESTRAINT OVERCURRENT RELAY
52	AC CIRCUIT BREAKER
59	OVERVOLTAGE RELAY
63/GA	TRANSFORMER GAS RELAY ALARM
63/GT	TRANSFORMER GAS RELAY TRIP
63/OA	TRANSFORMER OIL LEVEL ALARM
64G	GENERATOR GROUND FAULT RELAY
86	LOCKOUT RELAY
87	DIFFERENTIAL CURRENT RELAY
81I O/U	OVER/UNDER FREQ. RELAY FOR INCOMING LINE

FIG.1

TECHNIQUES DE DESSIN BASÉES SUR LES NORMES ACNOR B78.1 ET B78.2
DRAFTING PRACTICES BASED ON C.S.A. STANDARDS B78.1 AND B78.2

REVISIONS

CLIENT · CUSTOMER

DIVISION ÉNERGIE · ENERGY DIVISION
DOMINION BRIDGE-SULZER INC. LACHINE, QUÉBEC
CANADA

TYPICAL
SINGLE-LINE DIAGRAM

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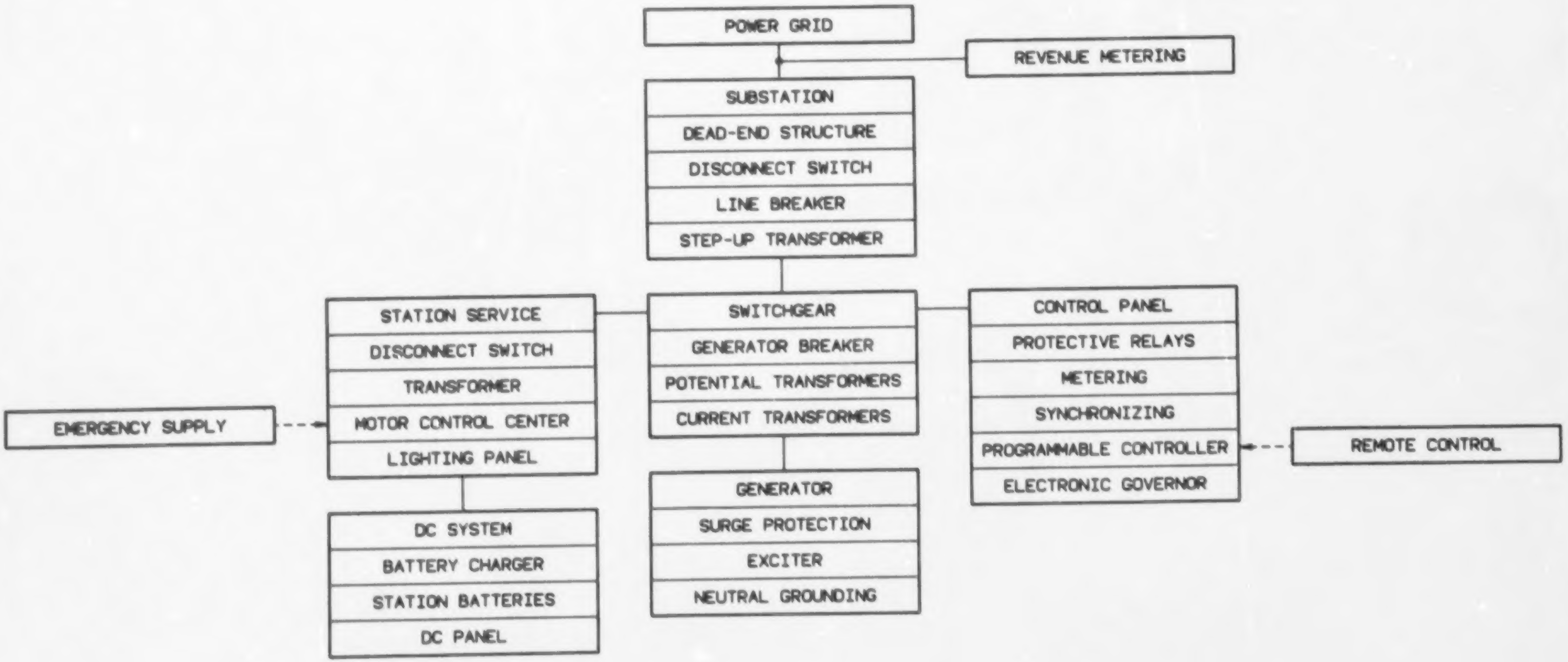
POWER GRID
REVENUE METERING
SUBSTATION
DEAD-END STRUCTURE
DISCONNECT SWITCH
LINE BREAKER
STEP-UP TRANSFORMER
STATION SERVICE
DISCONNECT SWITCH
TRANSFORMER
MOTOR CONTROL CENTER
LIGHTING PANEL
EMERGENCY SUPPLY
SWITCHGEAR
GENERATOR BREAKER
POTENTIAL TRANSFORMERS
CURRENT TRANSFORMERS
CONTROL PANEL
PROTECTIVE RELAYS
METERING
SYNCHRONIZING
PROGRAMMABLE CONTROLLER
ELECTRONIC GOVERNOR
REMOTE CONTROL
DC SYSTEM
BATTERY CHARGER
STATION BATTERIES
DC PANEL
GENERATOR
SURGE PROTECTION
EXCITER
NEUTRAL GROUNDING

FIG. 2

REVISIONS

NO. DE DESSIN DU CLIENT
CUSTOMER'S DRAWING NO.
ASM
CONTRAT
CONTRACT
PL-
QTE
QTY
CLIENT - CUSTOMER
DESSINE-DRAWN
SOUDURE
WELDING
VERIFIE-CH'KD.
EMIS
ISSUED
EXAMINE-REVIEWED
PROJECTION
APPROUVE-APP'VD.
ECHELLE:
SCALE:
DIMENSIONS:
REF.
FEUILLE-SHEET
DE
OF
REV.
TITRE
TITLE
ELECT. SINGLE-LINE DIAG.
SHOWING MAIN SUPPLY ITEMS

TECHNIQUES DE DESSIN BASEES SUR LAS NORMES ACNOR B78.1 ET B78.2
DRAFTING PRACTICES BASED ON C S A STANDARDS B78.1 AND B78.2

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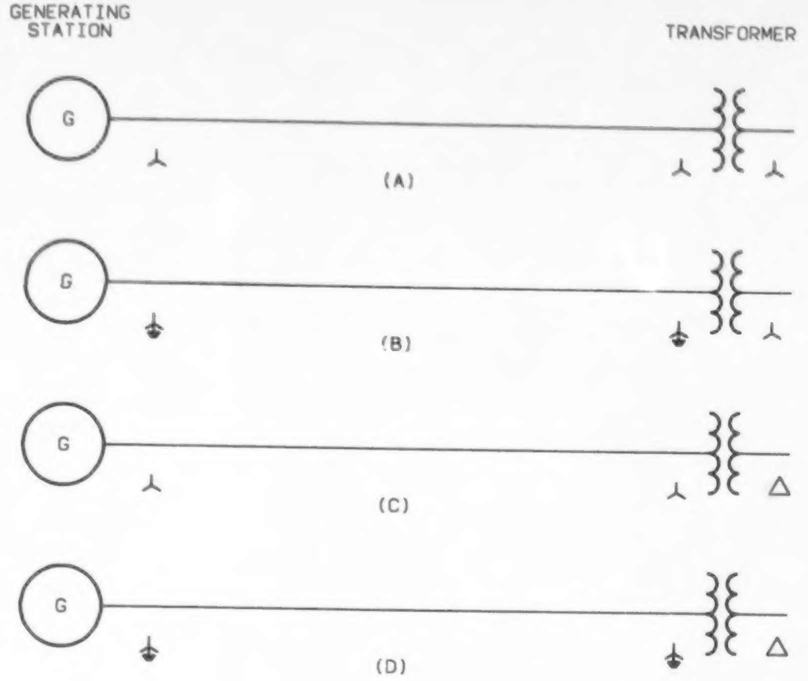

FIG. 3

NO. DE DESSIN DU CLIENT
CUSTOMER'S DRAWING NO.
ASM
CONTRAT
CONTRACT
PL-
QTE
QTY
CLIENT - CUSTOMER
REVISIONS
DESSINE-DRAWN
SOUDURE
WELDING
VERIFIE-CH'KD.
EMIS
ISSUED
EXAMINE-REVIEWED
PROJECTION
APPROUVE-APP'VD.

DBS ESCHER WYSS
DIVISION SULZER CANADA INC

ECHELLE:
SCALE:
DIMENSIONS:
REF.
TITRE
TITLE
TRANSFORMER
FEUILLE-SHEET
DE
OF
REV.

TECHNIQUES DE DESSIN BASEES SUR LAS NORMES ACNOR B78.1 ET B78.2
DRAFTING PRACTICES BASED ON C S A STANDARDS B78.1 AND B78.2

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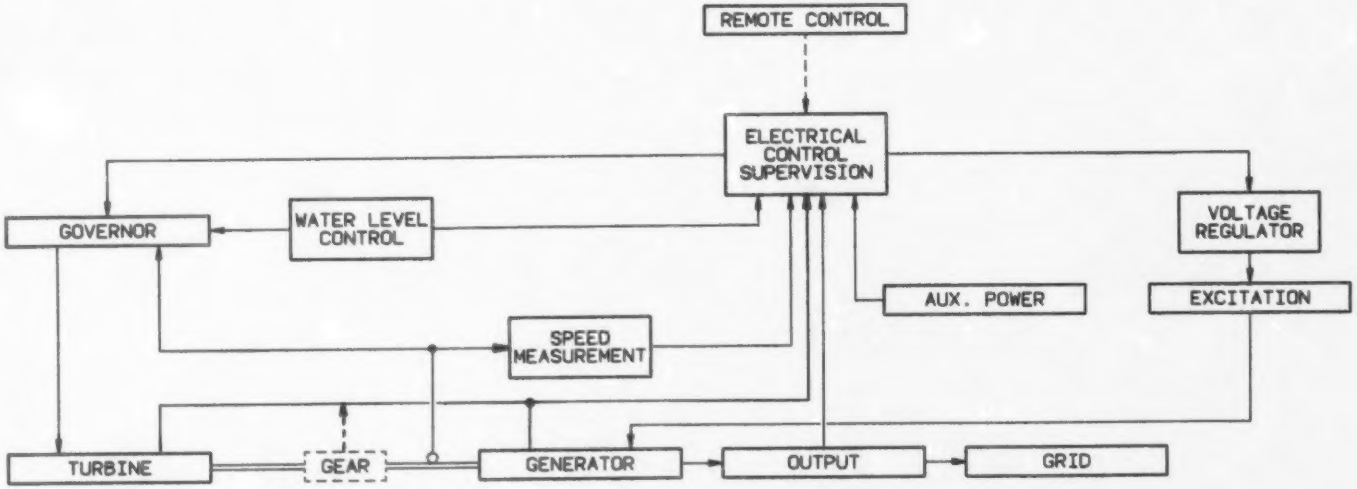
REMOTE CONTROL
ELECTRICAL CONTROL SUPERVISION
GOVERNOR
WATER LEVEL CONTROL
VOLTAGE REGULATOR
AUX. POWER
EXCITATION
SPEED MEASUREMENT
TURBINE
GEAR
GENERATOR
OUTPUT
GRID

FIG. 4

NO. DE DESSIN DU CLIENT
CUSTOMER'S DRAWING NO.
ASM
CONTRAT
CONTRACT
PL-
QTE
QTY
CLIENT - CUSTOMER
DESSINE-DRAWN
SOUDURE
WELDING
VERIFIE-CH'KD.
EMIS
ISSUED
EXAMINE-REVIEWED
PROJECTION
APPROUVE-APP'VD.

DBS ESCHER WYSS
DIVISION SULZER CANADA INC

ECHELLE:
SCALE:
DIMENSIONS:
REF.
TITRE
TITLE
CONTROL BLOCK DIAGRAM
FEUILLE-SHEET
REV.

REVISIONS

TECHNIQUES DE DESSIN BASEES SUR LAS NORMES ACNOR B78.1 ET B78.2
DRAFTING PRACTICES BASED ON C S A STANDARDS B78.1 AND B78.2

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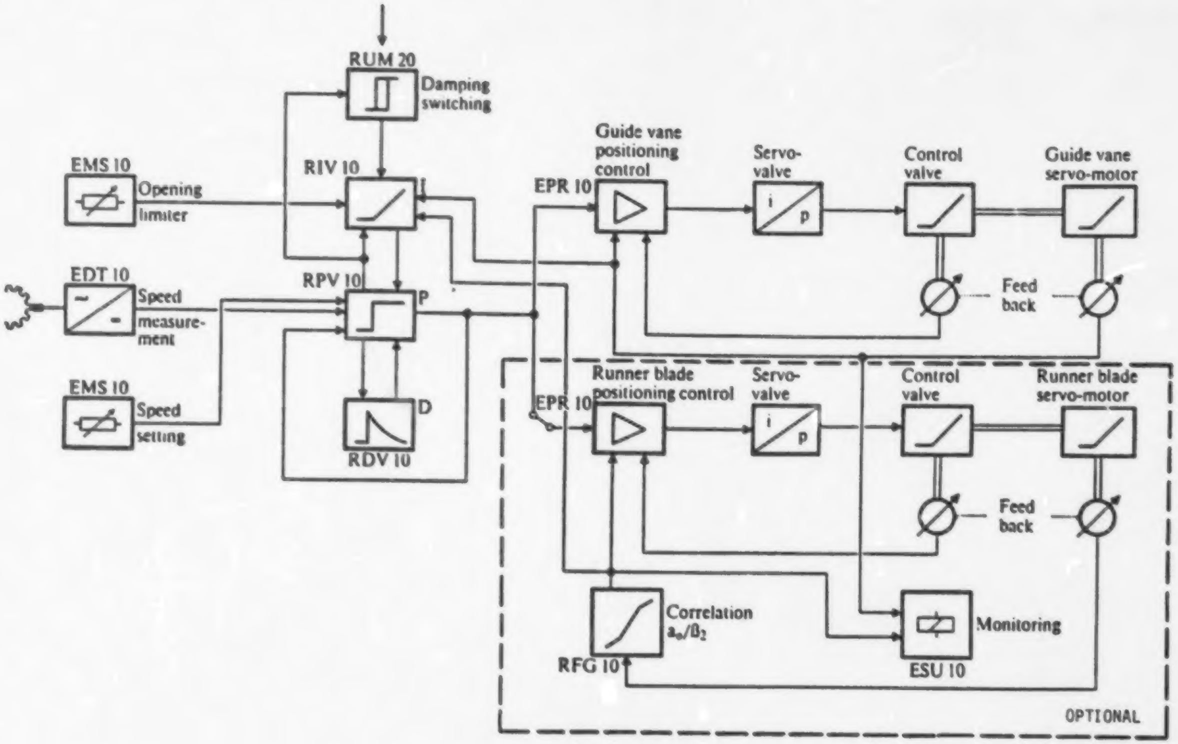
RUM 20
Damping switching
EMS 10
Opening limiter
RIV 10
I
EDT 10
Speed measurement
RPV 10
P
EMS 10
Speed setting
D
RDV 10
Guide vane positioning control
EPR 10
Servo-valve
i
p
Control valve
Guide vane servo-motor
Feed back
Runner blade positioning control
EPR 10
Servo-valve
i
p
Control valve
Runner blade servo-motor
Feed back
Correlation a_o/B_2
RFG 10
Monitoring
ESU 10
OPTIONAL

FIG. 5

REVISIONS

NO. DE DESSIN DU CLIENT
CUSTOMER'S DRAWING NO.

ASM

CONTRAT
CONTRACT

PL-

QTE
QTY

CLIENT - CUSTOMER

DESSINE-DRAWN

SOUDURE
WELDING

VERIFIE-CHK'D.

EMIS
ISSUED

EXAMINE-REVIEWED

PROJECTION

APPROUVE-APP'VD.

DBS ESCHER WYSS
DIVISION SULZER CANADA INC

ECHELLE:
SCALE:

DIMENSIONS:

REF.

TITRE
TITLE

FEUILLE-SHEET

DE
OF

REV.

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SESSION 20:

TURBINES 'B'

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Oscillating Hydro Energy Converter for Rural Development - Technological, Social, Economical and Environmental Issues

By
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The Oscillating Hydro-Energy Converter (OHEC) for Rural Development --- Technological, Social, Economic, and Environmental Issues

by

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ABSTRACT

The Oscillating Hydro-Energy Converter (OHEC) technology is introduced and some qualitative comparative appraisals made with other renewable and non-renewable small energy resources. Some remarks are made on the concept of decentralization in hydro-energy generation. Technological, social, economic, and environmental issues on the implementation of this novel technology in the context of rural areas in general, and rural developing areas in particular, are considered.

I. INTRODUCTION

The application of the Oscillating Hydro-Energy Converter (OHEC) for hydro-power generation is an innovative concept derived from aerospace technology. It has been proposed as a decentralized alternative to the conventional vertical and horizontal rotating axes hydraulic machines, especially where the available technological expertise, environmental considerations, economic constraints, and social consensus preclude the construction of dams across rivers and streams, and where the overall energy demand is relatively low. In the long run the success of the OHEC technology, given geographically suitable environments, could lead to the realization of extensive irrigation, agricultural product processing, drinking water supply, and electrification schemes in vast rural regions.

II. THE OHEC TECHNOLOGY AND APPLICATION

The OHEC technology of hydro-energy generation is based on the mechanical work extracted from the reciprocating motions of a system of wings (hydrofoils) exposed to a water stream flowing towards it.

This method of energy extraction is particularly relevant as a measure of "energy conservation in nature", where the dynamic energies of small streams or rivers, when not extracted, simply dissipate into the environment without being allowed the opportunity to perform useful work.

In power extraction operation the wings (hydrofoils) move with an undulatory mode. This lessens the destructive effect of silt and debris fouling on machine moving parts, and diminishes the possibilitiy of rotor entanglement by aquatic vegetations.

Since the wings (hydrofoils) oscillate in phased motions during operation, many options in the choice of geometric and kinematic parameters can be made to influence the mode of output and its performance characteristics. In particular, depending on the desired form of energy utilization at the site, suitable combinations of such parameters can be chosen to produce a rotary power output by appropriate linkage mechanisms. Or, the phased oscillating output can be incorporated as direct drive for energy conversion systems (e.g. linear electric generator, piston-type hydraulic pumps and pneumatic compressors).

Various possible applications for the energy extracted from rivers using oscillating wings (hydrofoils) can be envisioned. One specific concept involves the tapping of energy directly from the reciprocating wing (hydrofoil) motions to drive existing and/or modified pumping system in rural areas for irrigation purposes. The river or stream is thus utilized in the dual roles as water source as well as energy source. Such autonomous stations can be an alternative to those systems presently powered by human, animal or fossil fuel. Alternatively, an integrated "total-energy package" system can be designed such that all the electricity, water-supply, agricultural product processing, and irrigation demands of an individual agricultural community can be satisfied by an OHEC system.

III. STATE-OF-THE-ART

The OHEC has been under research and development (Figure 1) for the past seven years. From the advent of a working proof-of-concept model, the OHEC has evolved from early laboratory prototypes based on high-technology components and fabrication to simple designs which obviate sophisticated construction material and skill.

A small-scale integrated OHEC demonstration plant, designed specifically to simulate conditions in rural developing areas, was commissioned in July 1987 on the Eagle Mill Creek, Rensselaer County, State of New York, USA (Figure 2). The design made optimal use of parts of a bicycle, pieces of water pipe, and scrap wood and iron material. It was constructed largely out of wood in a garage over 10 weekends by two persons in a "do-it-yourself" manner. The demonstration plant also incorporated the capability for operation under extreme seasonal fluctuations of river or stream flow condition. The cost of construction material amounted to a few hundred dollars.

Operation experiences with the Eagle Mill Creek OHEC plant verified the adequacy of wood as structural material for OHEC construction. It was observed that wood also provided the unexpected added bonus of damping out noises and vibrations in the machine foundation which existed in the earlier high-technology versions of OHEC prototypes.

With the successful commissioning and testing of an OHEC prototype on a river the stage is set for the application of this hydro-power technology for irrigation, drinking water supply, agricultural product processing, and electrification. We now have a simple and robust design for the OHEC ready for implementation as decentralized pumping station, agricultural product processing plant, and/or electric generation plant by local people utilizing local material and local skills. Some observations on the OHEC technology compared to other renewable and non-renewable small energy resources are now offered.

IV. COMPARISION WITH OTHER SMALL ENERGY RESOURCES

IV. 1. Conventional Hydraulic Machines

The level of power output of the OHEC does not depend on the rotational velocity and/or radial and axial dimensions of a runner or impeller associated with conventional rotating axes machines, ranging from the traditional water-wheels to more sophisticated water turbines. Consequently, while upper limits on power convertible are imposed by centrifugal structural loading and cavitation on rotating wetted components of conventional machines, no similar constraints exist with the OHEC. Furthermore, above a limited capacity, the dynamics and kinematics of massive and extended rotating structures of conventional devices also necessitate sophisticated and often custom-designed and -manufactured gas and/or liquid lubricated bearing technology.

The rectangular frontal area of an OHEC conforms readily to river cross-sections. Consequently, a simple structural support with anchoring points on river bank and/or river bed should be more economical and less technically demanding than the foundations and ducting system of a rotating axis machine of conventional design.

Since the power output is in direct proportion to the number and dimensions of the oscillating wings (hydrofoils) in the system, the OHEC working principle can be used for a broad spectrum of output capacities in decentralized applications. Thus the OHEC offers potentials to be more readily adaptable to the site and application than the alternative conventional devices.

The relatively simple system of oscillating wings and linkages for drive system lends itself to easy adaptation to endogenous construction techology based on locally available material (such as wood, bamboo, fabrics, ropes and twines from natural fibre). This is in contrast to the mechanically more intricate design, manufacture, and maintenance of conventional water turbines.

IV. 2. Photovoltaic Cells

While actual reductions in the cost of photovoltaic (PV) systems do not quite keep pace with the optimistic predictions heralded in the past, substantial cost reductions of PV system has made it a serious alternative to other renewable energy resources, including small hydro-energy. What remains to be seen is whether the amorphous PV cell, which had up to now spearheaded the drive for cost reduction while showing in general relatively low (photon-to-electricity) conversion effficiencies and efficiency deterioration with service time, would ultimately attain the same high level of efficiency and reliability demonstrated by its more expensive mono- and polycrystalline counterparts.

Compared to PV technology, OHEC offers the primary advantage of simple design which is amenable to inexpensive local manufacture and native maintenance. On the other hand, the technology and manufacture of PV cells are, up to now, out of reach to almost all developing countries, so that all associated hardwares and whatever maintenance expertise needed would have to be imported. In the few developing countries which are exceptions, the production capacities for photovoltaic cells are largely dependent on capital intensive imported production facilities and processing material.

Since PV cells require sunlight for its operation, unless additional provisions are made for energy storage, a PV system cannot function as a base-load energy supplier unless it operates complementary to an additional renewable or non-renewable energy source to form an overall hybrid energy system. Both the energy storage option as well as the hybrid system option give rise to substantial inflation to the overall system cost. This is in contrast to the round-the-clock and in general all year round operation capability of the OHEC, unhampered by overcast, rainy or monsoon weather.

IV. 3. Wind Energy

Energy extractable from a dynamic fluid stream is proportional both to the density of the fluid and the third power of the fluid stream velocity.

The energy extractable from a dynamic water stream is expected therefore to exceed that from a dynamic air stream of equal frontal area at similar velocity by a factor theoretically equal to the relative densities between the two fluids (roughly a thousand times). This relative advantage of the OHEC versus wind turbines (including wind machines operating with the same working principle as OHEC but in air) is partially offset by the generally higher wind velocities prevailing at wind machine sites, and by the larger hydrodynamic dampings on wetted OHEC moving parts.

From the engineering perspective, river water as a pollution-free renewable working medium offers two additional advantages favorable for OHEC operation compared to wind. First, the unidirectional flow of rivers eliminates the need for directional control mechanisms for hydraulic machines, including the OHEC, which are essential for accommodating shifting wind directions in wind energy installations. Secondly, the relative constancy of water flow velocity can be relied upon for base-load energy supply by OHEC. Whatever flow velocity and flow volume fluctuations (mainly seasonal) can in most cases be accommodated by flow augmentation devices and/or with periodic relocation of the OHEC system on the river. This is in contrast to the need, in base-load operation, for installing an additional energy generation system as back-up for a wind energy system during periods of atmospheric calm or excessive wind velocities.

IV. 4. Gasoline and Diesel Prime Movers

It has often been asked why the task of supplying small amounts of energy cannot be fulfilled by operating small "lawn-mower" type gasoline or diesel engines.

Especially in the context of short term relative oil abundance in the world market, much has been said about the ease and economy of supplying low level of energy base-load demands using small gasoline or diesel engines. Protagonists point out that the capital investments in these installations may actually be compatible with, and in some cases lower than small hydro-energy devices such as the OHEC. Skeptics, on the other hand, point to the continuing economic and social costs, borne by the public at large, in the form of air pollution, acid rain, and possible global warming by the "green-house effect", contributed by the base-load operation of gasoline or diesel prime movers, which may or may not be easily quantified. A comprehensive assessment, however, should in the least take into account the issue of fuel supply and consumption, as well as maintenance over the life-cycle of the operation of such machinery.

In rural areas, the supply infrastructures for petroleum fuel products range from marginal to nonexistent, partly as a result of logistic problems over difficult or inaccessible terrains, but also because of the economics of distributing a relatively small total amount of petroleum fuel products in scheduled periodic intervals over a widely scattered area. There are, in addition, the questions of affordability of petroleum fuel products for rural developing populations in general, and the availability of foreign exchange for oil-importing developing countries in particular. Furthermore, there exist the problems of availability of spare parts and technical maintenance skill to service these machinery in developing countries.

It has been pointed out repeatedly in international development fora, that oil price fluctuations in the world market has little or no effect on the problems of supplying energy to rural developing areas.

V. DECENTRALIZATION IN HYDRO-ENERGY GENERATION

The concept of energy supply using large dam-turbine hydro-power installations can be looked upon as an avenue to scrape together first widely scattered potential energy sources on the entire stretch of the river and accumulating these on a single spot for the concentrated exploitation of energy, and then dispersing these energy "concentrate" to the end consumers. It grew out of the conventional wisdom of economy of scale of power generation equipments and reflects the mode of production and life style evolving out of industrial and urban developments.

How does this concept look when the cost of dispersing these energy "concentrate" to the end consumer is factored into the overall picture? According to a study prepared for the United Nations Institute for Training and Research (UNITAR) on the occasion of the 1984 UNITAR International Conference on Shale Oil and Gas, capital investments on electrical transmission line run between US$150,000 to US$500,000 per mile, depending on the voltage. These investments on power distribution may be justifiable in areas of high energy demand and concentrated energy consumption, predominantly in industrialized and urban societies.

What does require closer scrutiny are situations in rural communities of developing countries, where the energy needs, although vital for the overall development process, are by virtue of the scattered nature of the local economic activities (1) not geographically concentrated, and (2) often in absolute terms only in the order of magnitude of hundreds to thousands of watts for an individual community */. The economy of scale of conventional hydro-power equipments that is favorable to centralized power generation may not necessarily off-set the high cost of power distribution in these situations. The technical problems imposed by difficult and often inaccessible terrain over which power transmission lines need to be constructed and serviced further tip the balance in the overall picture.

From the rural development prospective, shouldn't there be an alternative to the double-tracked avenue of deliberately concentrating potential energy sources from a long stretch of the river at a single spot for energy generation, then having to disperse the usable energy "concentrate" again to the individual consumers (and paying high economic, social, and environmental costs in the process)? Isn't it relevant for the community of policy-makers, economists, and technologists concerned with energy issues for development to take a closer look at the concept of generating just enough energy to supply a rural developing community in the vicinity where it is ultimately consumed, utilizing decentralized energy generation?

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*/ This situation is also reflected in the experiences documented in a paper presented in this Conference. Even with operating "small" hydro-energy plants, the author (J. L. Bidwell) reported on load factors as low as 15 to 30 percent in rural areas in Nepal.

Many villages in rural developing areas are situated close to rivers because of the need for water supply. The OHEC offers one possible technology for such decentralized energy generation. In an extreme decentralized setting, this technology can even lead to "a power plant in every backyard".

VI. SOCIAL, ECONOMIC, AND ENVIRONMENTAL IMPACTS

The realization of the present energy extraction system on rivers does not necessitate the construction of dams across waterways. From the perspective of appropriate technology for development, this may alleviate some of the socio-economic problems associated with the availability of capital investment and technical expertise. Furthermore, it also circumvents the social and economic problems of flooding fertile farmlands in low-lying river bank areas, as well as preserving the natural habitat and ecological balance for wild lives while keeping the river unobstructed for navigation, fishery, recreation, and aquatic life migratory cycle.

Much has been said on the motivations of the development of the OHEC technology as a new and renewable source of energy, as well as its socio-economic impacts on rural developing areas in general 1/ 2/ 3/ 4/ 5/ 6/ 7/, and, in particular, on the development of rural women 8/, in the context of the priorities set forth in the Nairobi Forward-Looking Strategies for the Advancement of Women 9/. Some areas of the implications of the OHEC technology for rural development are now outlined.

VI. 1. Rural Electrification

One of the major area of the application of OHEC pertains to the production of electricity for heating, lighting, and cooking in place of firewood and other organic fuels in many areas of the developing world. Since no dam or other civil work is needed, there is very little restriction on the choice of the OHEC power plant site on the river. Consequently, the electricity demand of a typical rural community in a developing country, usually in the order of kilowatts, can be adequately met by one or several OHEC power plants situated close to the community they are built to serve. This leads to significant savings over the costs and the technical equipments for high voltage power transmission over long distances. The availability of electricity would reduce the drudgery of foraging and transporting firewood and other organic fuels, all too often performed by women and children in the rural areas of the developing world. The advent of a reliable source of electricity in the village level also pave the way for the installation of small cold storage facilities for preserving the quality of vaccines to combat endemic local diseases and other diseases in the rural population.

VI.2. Domestic Water Supply

Large numbers of decentralized water pumping stations based on the OHEC technology can be constructed in rural areas which draw both their power and their water inventory from running rivers. No fuel, human energy, or draught animal power need to be expended in the process and the water supply is available round the clock, 365 days a year, as long as the river is running. The water can be delivered, over short and long distances, to human settlements in the form of communal or domestic water supply for drinking, cooking, laundry, and sanitation. The availability of such water-delivery system powered and supplied by nature will go a long way in reducing the drudgery of water ferrying that constitutes a significant part of the work of rural inhabitants in the developing world.

VI.3. Food and Agricultural Technology

One of the major impact of the OHEC technology on food production and agricultural technology on the village level of developing areas is the feasibility of constructing and maintaining automatic irrigation schemes which relieve the rural population from ferrying water or manually operating water transport devices to irrigate agricultural plots. Since water can be transported over long distances from where it is available to where it is not available using the OHEC technology, the rural farmer is ensured reliable supply of irrigation water for his crops during dry season or drought periods **/. The use of agricultural machinery powered by energy from OHEC installations can also relieve the rural farmers from time- and energy-consuming harvesting and agricultural product processing tasks, as well as increasing their productivity and income. Furthermore, energy will be available for refrigeration and drying to preserve perishable food items.

VI.4. Rural Employment

There is another aspect of the OHEC technology which has a profound impact on the rural economy. Although the OHEC technology is conceived originally from high-technology, its implementation has been developed in the last few years to the stage of a "do-it-yourself" design which can be built based on the indigenous skill and material accessible to the rural population. Local workshops and co-operatives on the grass-root level can thus be organized for the manufacture, operation, and maintenance of OHEC power plants which would offer both employment and enterprise opportunities for the native

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**/ It was observed that even during the recent severe drought in Ethiopia, some mountain rivers in the country were still flowing at more or less normal rate, although they are remote from populated areas.

communities, reducing impetus for rural exodus to urban areas.

VI.5. Environment

The welfare and livelihood of a large number of inhabitants in rural areas have been threatened by such man-made or natural disasters as droughts, floods, soil erosion, deforestation and desertification. OHEC technology would contribute both to the prevention as well as eventually to the reversal of these environmental degradation. First, by substituting fuel wood for electricity as domestic cooking and heating energy source, pressure on the removal of trees and vegetations for fuel would be curtailed. The preservation of trees and vegetation prevent soil erosion from the action of wind and water. Furthermore, plant roots and the soil they dwell on help retain ground water during rainy season, alleviating the risks of floods, and making water available to avert a drought in dry seasons. Secondly, since considerable amount of water can be pumped by the continuous action of large numbers of inexpensive OHEC pumping stations, it is conceivable that over a number of years, coupled with rigorous tree-planting campaign, that desertification can actually be halted or even reversed through reforestation.

VII. CONCLUSION

The OHEC technology does not constitute a universal solution to all potential implementations of rural energy supply. Depending on the given geographical and local community conditions, it may operate in an autonomous stand-alone mode or in tandem or hybrid mode with other alternative renewable small energy resources (e.g. conventional hydro-turbine, wind, solar, biomass, geothermal, and plant derived hydrous ethanol) to provide the most appropriate overall energy supply package conducive to rural development for a specific case.

Nevertheless, for applications in rural areas of developing countries, and remote areas of industrialized countries, it offers, among other positive attributes, the advantage of inexpensive local construction and maintenance of decentralized base-load hydro-power plant utilizing indigenous material and native skills. The OHEC technology is particularly an attractive alternative in situations where the available technological expertise, environmental considerations, economic constraints, and social consensus preclude the construction of dam-turbine installations across rivers and streams, and where the overall energy demand is relatively low.

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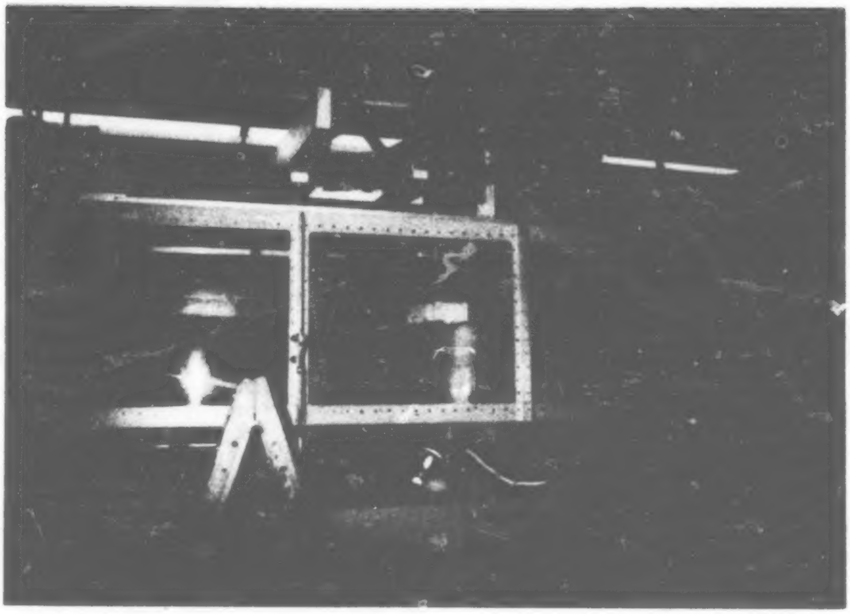

Figure 1: Photograph of Oscillating Hydro-Energy Converter (OHEC) Model Apparatus designed for Water Channel Testing as Simulation to River Operation

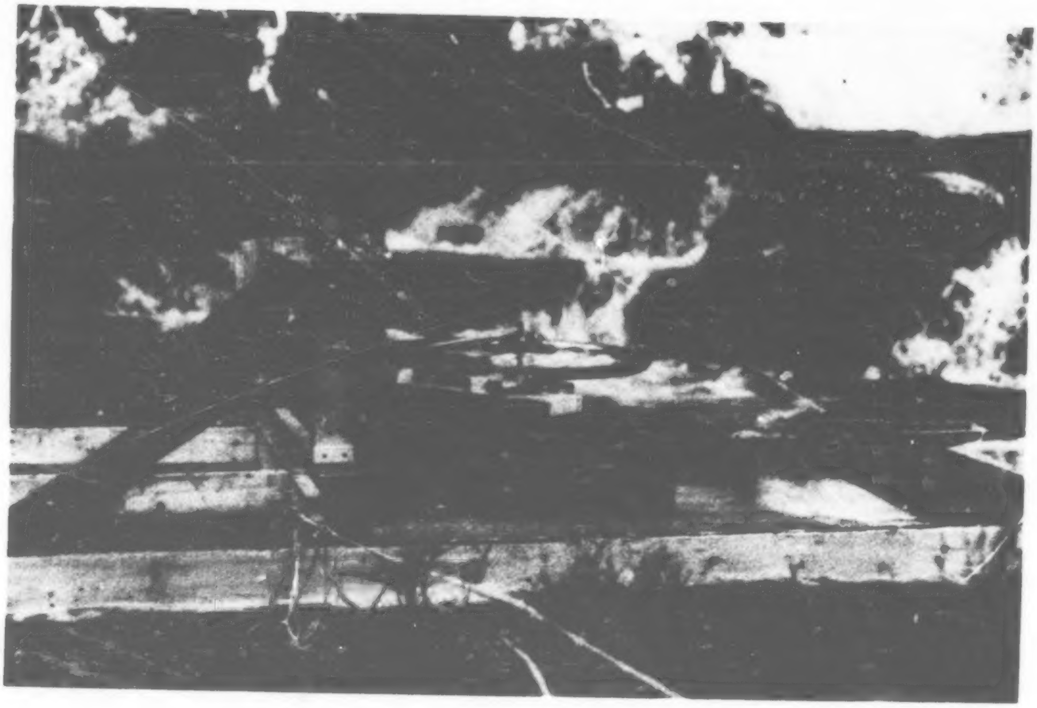

Figure 2: Photograph of Integrated Oscillating Hydro-Energy Converter (OHEC) Prototype Plant in Operation on the Eagle Mill Creek, Rensselaer County, State of New York, USA

Siphon-Types Conduit System in SHP of China

By
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SIPHON-TYPE POWER CONDUIT SYSTEM IN SHP OF CHINA

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SIPHON-TYPE POWER CONDUIT SYSTEM IN SHP OF CHINA

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Siphon intakes were first used in West Germany and Switzerland in 1950s (1). In 1960s, one large siphon-type SHP station was built in West Germany, comprising two units, with unit capacities of 6 MW and 11.5 MW respectively. This plant might be the largest siphon-type station in the world. USSR built its first siphon-type plant (Kubanck station) in early 1970s (2). First siphon intakes in China were built in Qinhai and Zhejiang provinces, as well as Xingjiang Autonomous Region, in late 1960s, without knowing the information abroad. Even for these provinces, they developed their own siphon intakes independently until late 1970s (3). Independent experiences and lessons in various regions have presented a colorful picture of SHP siphon-intake development in China. In 1985, under the directive of the Ministry, the author led a team to investigate this type of intake in a nationwide scale (3). Among others, it was found that the siphon intake, penstock layout, priming and breaking system, valve layout and the governor should be considered as a whole system, and the terminology "siphon intake" had better be replaced with "siphon-type power conduit system".

I. ADVANTAGES OF SIPHON-TYPE CONDUIT SYSTEM

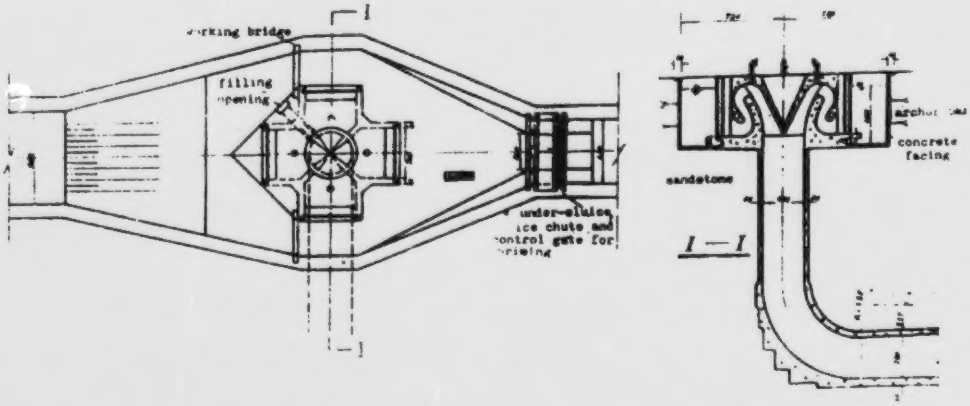

Fig.1 Siphon-intake of Guanting hydro plant

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Fig.1 is the Guanting hydro plant in Qinhai province, which was the first siphon-type plant in China, completed in 1968. This station is of combination type, with a design head of 19 m and a design discharge of 14 m^3/s, comprising 2X250 kW and 1X320 kW generating units and 1,280 kW capacity of turbine-pumps*.

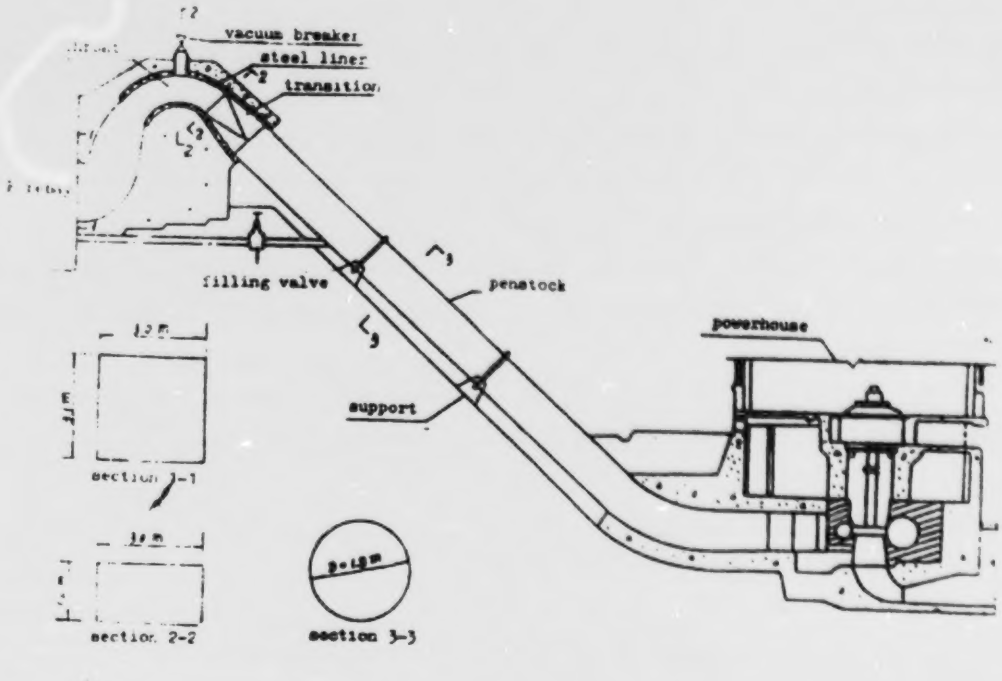

Fig.2 Profile of Dishan plant with 2X2,000 kW units

Fig.2 is the profile of Dishan siphon-type plant, a typical example in Zhejiang province, housing 2X2,000 kW units, with a design head of 28 m and a unit discharge of 9.46 m^3/s. The penstock is of one-penstock-for-one-unit layout, without butterfly valve before the turbine. After being commissioned, tests showed that the unit could be started by self-priming, which was appreciated by the operator because of: a) convenience for operation; b) being much quicker than the vacuum pump does; c) saving electricity. Afterwards, the vacuum pump was no longer used. In 1981, an overall field test (including runaway tests) gave good performance results in respect of swing and vibration of the unit, vibration of the penstock, stability of the local grid, water hammer pressure and speed rise.

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* The coaxial unit of turbine and pump is a special water-lifting device in China.

Practice shows that this type of conduit system has following advantages (3):

1) Elimination of intake gates, even the front valve if one-for-one layout is adopted.

2) Compared with gated intakes, 25-30% of first cost can be saved for the conduit system.

3) In cold regions, ice problems can be greatly reduced and it gives some positive effect on silt prevention of the intake.

4) Compared with gated intakes, the plant flow can be cut off more quickly and completely, and the conduit system is more convenient and reliable in operation, thus reducing the M & O cost.

5) During speed regulation by the governor, the water hammer and speed rise are similar to those of gated intakes. During emergency shut-down by vacuum breaker or injector-piping system (described hereafter), its water hammer and runaway condition are much better or at least equal to those of gated intakes, depending on the increase of plant head.

The disadvantage of siphon intakes, if any, is its application range that it can only be used in diversion-type plants or reservoir plants with headrace fluctuation less than 4-5m. In addition, when the plant head is small, say less than 4m, use of siphon intakes might be unreasonable because of the vacuum impulse at the ceiling and draft tube or tailrace.

II. Configuration of Conduit System

In principle, the design and configuration of the conduit are same as those of ordinary penstocks.

According to our experience (including lab and field tests), the head loss resulting from the siphon bend (generally a circular bend) is not greater than that of gated intakes. In our initial development, the inlet velocity of siphon intakes was 0.8-1.2 m/s as generally adopted in gated intakes, in aim of decreased head loss. Field and model tests showed that the head loss of siphon intakes was about equal to or even smaller than that of gated intakes because of no gate, no gate slots and smooth transition, especially for the circular or conical inlet, which later on was generally favored by the designer. In addition, the velocity at the inlet and control section was raised to 1.5-2 m/s and even 2.5-3 m/s respectively because:

1. the separate layout of the trashrack and the inlet could decrease the head loss and improve the structural and maintenance condition;

2. greater velocity at the control section is beneficial to the self-priming.

It should be noted that the max. water level at the forebay be lower than the crest elevation by 0.1-0.15 m. But attention should be paid to such a case that one unit or penstock is under repair or maintenance whist others are suddenly rejected from the load. In this case, the hydraulic bore in the forebay would result in overtopping of the crest, giving a safety hazard to the maintenance personnel inside the empty passageway.

III. Minimum Submergence Depth (3)

It is known to all that the inlet should be well positioned below the min. water level of the forebay in aim of: 1) preventing formation of air-entraining vorteces; 2) preventing air directly from being entrained into the siphon; 3) preventing floating ice, if any.

However, great submergence would result in more excavation and concrete. At present, there are many empirical formulas for determining the min. submergence (6;7;8;9;10). According to author's analysis (3), the Gorden's formula, J.Knause's formula and Han's formula are reasonable for the siphon inlet. Han's formula was proposed for siphon intakes, based on the design practice of our earlier siphon intakes, most of which were rectangular inlets and designed on a conservative basis. The author had verified some formulas based on field test data of three existing siphon-type plants (all of horizontal intakes of rectangular inlets). In China, the submergence depth of most existing projects are generally greater than 2m even 2.5m, which are thought conservative by most Chinese engineers. Our fact is that existing siphon intakes of rectangular inlets are working steadily under a sumergence depth of 0.5d*.

At present, Chinese engineers incline to using circular inlets and raising the inlet velocity, which would result in greater Froude number. The author inclines to such a recommendation that, combining the J.Knause's formula and Han's formula with some modifications to the constant, following formula is recommended:

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* In the past, our designed value of d (height of the inlet) is rather great.

$$hs/d = 1.5\ Fr + 0.3 \text{ (for rectangular inlets)} \qquad (1)$$

$$hs/d = 1.5\ Fr + 0.2 \text{ (for circular inlets)} \qquad (2)$$

in which, hs--min. submergence depth; F_r--Froude number at inlet, $F_r = V_{in}/\sqrt{dg}$ (V_{in} is the average velocity of the inlet); d--diameter or height of the inlet; g--gravitational constant.

Considering that since this subject has not been specifically studied, the submergence depth had better be determined on a reasonably conservative basis though smaller submergence could save some construction quantities. It should be noted that in cold regions the min. submergence depth should be determined, taking into consideration the frozen thickness or the regime of floating ice.

IV. PRIMING AND SHUT-DOWN OF SIPHON-TYPE CONDUITS

Siphon intakes abroad were all designed to be primed by vacuum pumps and shut down by vacuum breakers, and the self-priming was used as a supplementary measure during operation. In our initial development, these methods were also generally used. Our practice showed that these methods had following demerits: a) the first cost was high; b) this priming method took a longer time, generally 15-25 minutes*; c) it needs a reliable power source. Since the priming method by vacuum pumps is well known to all, here it will focus on those innovations in our SHP practice.

1. Priming by Gates or Stoplogs on Side Spillway

A side spillway is generally located in the forebay, with its crest to be even with the max. water level. If a gate or stoplogs of appropriate height are specifically installed on the spillway crest, it can temporarily raise the water level to prime the siphon. Our first siphon-type plant, the Guanting hydro station in Qinhai province, adopted this method.

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* If a shorter priming time is required, there would be larger capacity of vacuum pumps.

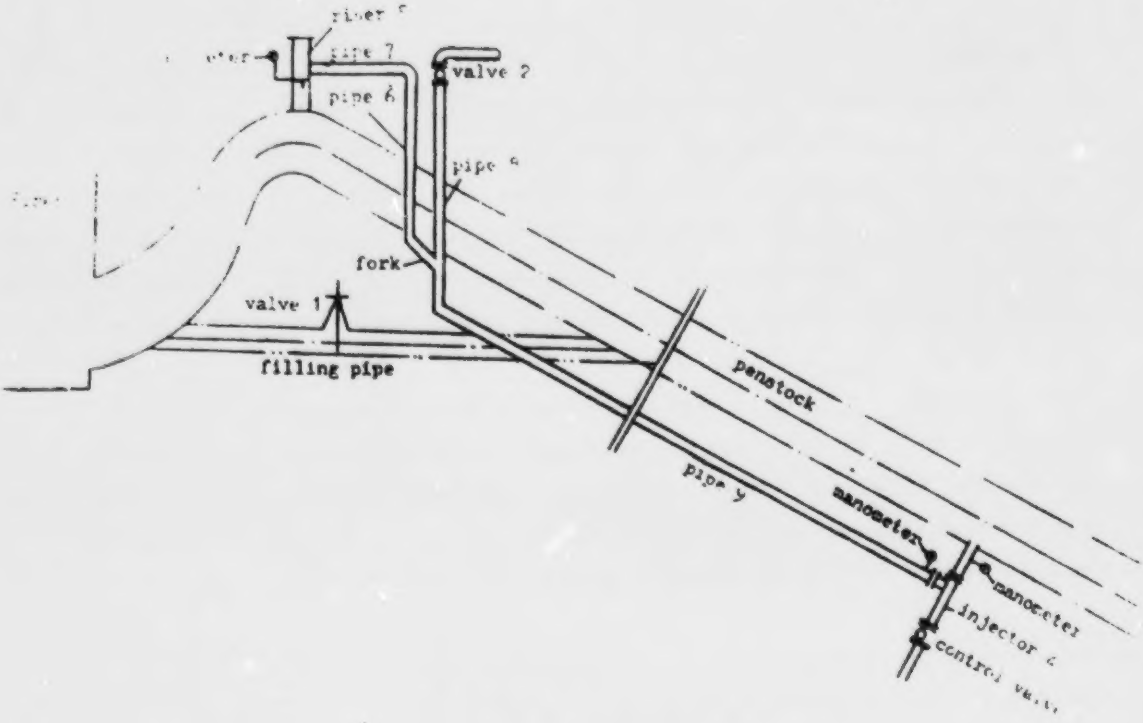
riser 5
pipe 7
valve 2
pipe 6
pipe 8
fork
valve 1
filling pipe
penstock
pipe 9
manometer
manometer
injector 4
control valve

Fig.3 Sketch of injector-piping system

2. Injector-piping System (6;3)

This system was invented in Qinhai province in 1970s. Its working principle can be clearly seen from Fig.3.

1) Priming the conduit

a) Open valves 1 and 2 and fill up the conduit to be even with the water level in the forebay;

b) Close valves 1 and 2 and open the control valves 3 to let the injector 4 work under the pressure of the conduit; water in the piping system is quickly evacuated and subatmospheric pressure created in the whole system as designed, i.e. the water surface in the conduit rises up to the pre-designed stage as shown in the riser;

c) Open the valve 2 for emergency shut-down, if any, and then put the unit into operation.

2) Normal operation

During normal operation, the load of the unit is regulated by the governor. If the unit should be shut down for a short time, say less than 14 hr, the whole conduit can be kept full for its next loading-in, without any priming.

3) Emergency shut-down

If some accidents take place, the control valve 3 is opened by an auto-switch and the injector begins to work. As soon as the water level in pipes 6 and 8 (Fig.3) below the fork, the vacuum in the piping system quickly breaks off and the flow in the throat can be cut off within several seconds. The whole process can be done within 25-30 seconds (which is mainly taken by valves' action), much shorter than an emergency gate does.

During design of this system, designers should bear in mind that: a) the riser 5 should be high enough to avoid the water rising up to pipe 7, based on the design vacuum used; b) the fork should be well positioned low enough to keep the water column for sealing the fork; c) in cold regions, the piping system should be properly protected from freezing.

The merits of this system are as follows:

a) Simplicity in construction.

Except those valves and monometers, which should be purchased from the market, the whole system can be made in the contractor's workshop.

b) Durability and reliability in operation with little maintenance.

c) This system can function as the primer and also the vacuum breaker.

d) Saving first cost due to its low cost and the elimination of the vacuum breaker.

e) It can be remote-controled or operated by hand if no power source exists. The latter is quite significant for remote or isolated plants.

The demerit of this system, if any, is its application condition that the plant head should be greater than 12 m for producing the high velocity as desired by the injector or the design vacuum. However, the head of diversion-type plants is generally greater than this value.

3. Container-type Primer (11)

This type of primer is also an innovation in siphon-type plants of China. Its working principle is similar to that of a piston pump and can be seen in Fig.4.

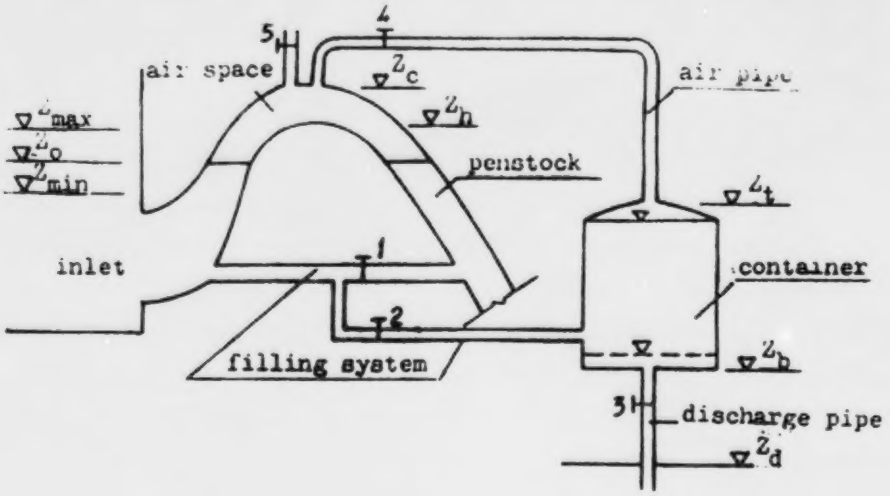

Fig.4 Sketch of container-type primer

Having been filled up to be even with Zo in the forebay together with the container being filled up to its upper most water level (Fig.4), the conduit can be primed by following procedure; close the valve 5 (i.e. the vacuum breaker) and then open the valve 3; the water level in the container falls down (the water body in the container works as a piston), the pressure in the air space decreases due to volume expansion and the water level in the conduit rises up until it reaches to the height as designed. Close the valve 3 and put the unit into operation.

This type of primer can be also remote-controled or operated by hand if no power source exists, but cannot replace the vacuum breaker.

This type of primer can be easily understood by hydraulic engineers. Its minimum volume can be determined by Boyle's law and the actual volume should be equal to (1.2-1.5) minimum volume of the container. The container can be arranged in the forebay dam or separately located; its form can be of cylinder-type or box-type, depending on concrete conditions. In any case, its strength and collapsing-resistance should be verified.

Second, the top of the container should be located below the headrace level at which the conduit is primed so as to fill up the container by the filling system. The height of the container is generally determined by the container volume and its form shape and the length of the discharge pipe (Fig.4) should be greater than the design vacuum (m). Thus the water in the container can be discharged into the tailrace or atomosphere while the water in the container can be discharged into the tailrace or atomosphere while the water level in the container is under its lowest position. As a result, the $(Z_{max} - Z_{d})$ should be greater than 7--11m in general.

Zhejiang Provincial Hydraulic Research Centre (ZPHRC) had carried out some lab tests on self-priming of siphon intakes. However, our model tests and field studies on this subject are still limited, such a definite discriminant as to identify the self-priming has not been found yet, and it should be further studied, especially based on field data (12). But operation practice showed that if the velocity at the throat is greater than 2.2--2.5m/s, depending on the magnitude of design vacuum, self-priming can be expected.

V. WATER HAMMER, SPEED REGULATION AND RUNAWAY CONDITION (3;5)

Siphon-type plants which are regulated by governors have the same conditions as conventional plants in respect of water hammer and unit speed rise. As far as the runaway condition is concerned, the siphon-type plant is better than or at least equal to conventional plants. Theoretical analysis and field tests showed that emergency shut-down (while the governor malfunctions) by vacuum breaker or injector-piping system can break up the siphon within 25 - 30 seconds, more quickly than an emergency gate does, with a much smaller water hammer rise than that of a complete shut-down by the governor or butterfly valve. And also, the max. speed rise of the unit of siphon-type plants, resulting from the water in the penstock, is less than the runaway speed specified by the manufacturer. But this advantage gradually vanishes with the increase of the plant head, because the penstock length increases with the plant head and more water would accelerate the unit. Therefore, for high head plants (say, greater than 100m) a butterfly valve would be provided closely before the turbine. However, in high head plants, one-for-multi-units layout is generally economically feasible and such a front valve is needed in general. In very high head plants, adoption of Pelton turbine would greatly improve its runaway condition and no front valve may be needed.

VI. DESIGN VACUUM AND APPLICATION RANGE OF SIPHON INTAKES

Unlike the siphon spillway, there is no hazard of cavitation in siphon intakes because of the smaller velocity at the throat. In the existing reinforced concrete siphon intake of China*, there have been no cavitation being found. However, the design vacuum at the siphon ceiling could not be too high because: a) fine air bubbles in the flow would be released at the low pressure area, thus resulting in an air pocket which might lead to instability of the unit output, even to break-up of the siphon; b) larger design vacuum would lead to less dependability of self-priming during operations as mentioned above.

The max. vacuum at the siphon ceiling should meet following formula:

$$hvac \geq (Z_{max} - Z_{min}) + \Delta h + ho \text{ (or do)} + Vo^2/2g + \sum hw \qquad (3)$$

in which, Z_{max} and Z_{min} are shown in Fig.4; Δh--difference between the Z_{max} and crest; ho and do--height or diameter of the throat (i.e. control section); V_o --average velocity at the throat; Σh_w--head loss from inlet to the throat.

Meanwhile, hvac should be less than the max. permissible vacuum at the locality, thus:

$$hvac < \left(\frac{Pa}{\gamma} - \frac{\nabla}{900} \right) - \frac{Pv}{\gamma} - \beta\frac{Vo^2}{2g} \qquad (4)$$

in which, $\frac{Pa}{\gamma}$ --- atmospheric pressure at mean sea level, 10.33m; $\frac{\nabla}{900}$** --- a correction for the site altitude (m); $\beta\frac{Vo^2}{2g}$ --- vacuum impulse, β= 0.2 for circular inlet and β = 0.3 for rectangular inlets; $\frac{Pv}{\gamma}$ --- vapor pressure (or vapor tension), which can be adopted from some reference books.

In high-altitude regions, application of siphon intakes is mainly determined by the altitude of the site, the magnitude of fluctuation of headrace levels and ho or do. In other words, formulas (3) and (4) should be met. Most existing siphon-type plants in Qinhai province are located at elevations of 2,100 - 3,600 m above mean sea level. The Qumalai hydro plant is situated at elevation of 4,078 m, housing 2X320 kW units and might be the highest-altitude plant in the world.

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* R.C. siphon intakes have less gas-proofing capability. Our practice shows that steel liners for the siphon section is needed if the penstock is of R.C. or prestressed pipes.

** If the altitude of the site is greater than 3,000m, the term $\frac{\nabla}{900}$ should be replaced by $\frac{\nabla}{1050}$.

In low-altitude regions, application of siphon intakes is actually determined by formula 3.

In our practice, the design vacuum was generally 4 -5 m and no greater than 6 - 7 m depending on the site altitude. As mentioned above, smaller design vacuum should be used as far as possible, especially in high-altitude regions.

In addition, the penstock discharge gives also a limitation to the application of siphon intakes because of ho or do in formula 3. According to author's analysis, when the discharge is less than 15 - 20 m^3/s, the circular inlet can be considered, and when the discharge greater than 15 - 20 m^3/s, the rectangular inlet is preferable. And, the limitation to the penstock discharge and high altitude of the site may affect the preference of the circular inlet (or throat) alternative.

VII. A CASE STUDY (13)

The Dieshui No.2 hydro plant is located on the Bajiang creek, a tributary in the upper reaches of Nanpan river in Yunnan province, comprising 3X630 kW units, with a design head of 26.1 m and a design discharge of 3X3.2 m^3/s. The diameter of the penstock is 1.8 m, totaling 62 m long, terminated with three branch-pipes and butterfly valves (ϕ1,200mm) to each unit. Fig.5 is the siphon intake of Dieshui hydro station. The whole intake section was composed of two parts: the conical inlet and the 1.8 m diameter bend, as shown in Fig.5. This vertical-upward conical pipe is 6 m long with an inlet diameter of 2.11m, flared with an angle of 4°30'. The intake was symetrically arranged, with good approaching condition of inflow to avoid vertical vortices. The whole intake pipe section was openly supported on the top of the valve chamber, only anchored with two U-type anchor rods. In addition, a smaller submergence depth (1.5m) was used and the height of the inlet over the forebay floor only 1.2 m, thus reducing the excavation depth by 1.5 - 2 m. The diameter of the bend is equal to that of the penstock. The layout and configuration of the intake are simple and compact, and convenient for construction and installation, with little maintenance. Since the operation in 1981, no troubles, such as instability, notable vibration etc., have been found.

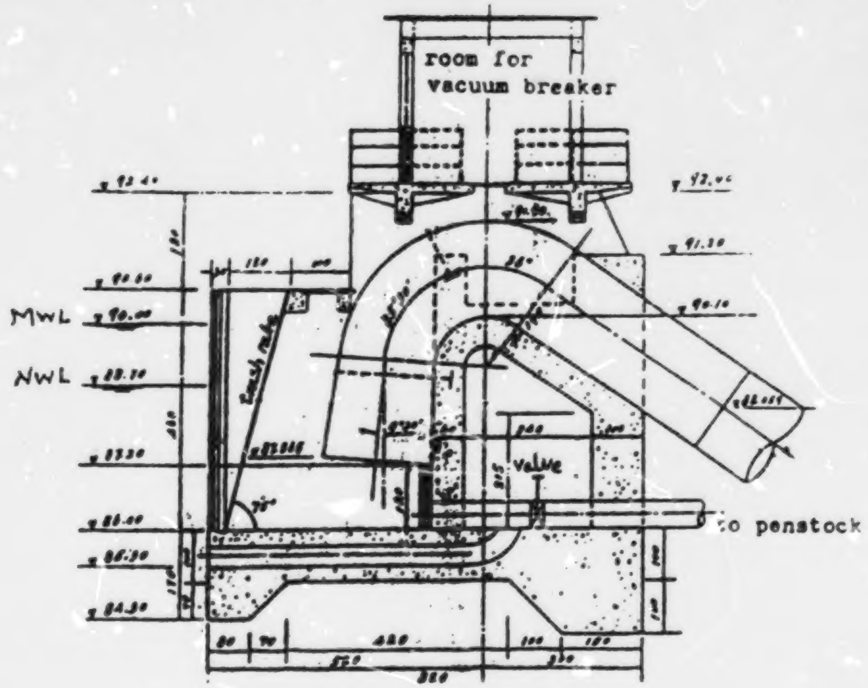

Fig.5 Siphon intake of Dieshui plant with 3X630 kW units

The design vacuum at the siphon ceiling was -4.18 m, which was determined by formula 3 under the condition that three units were full loaded at a headrace level of 88.7 m. According to formula (4), the max. permissible vacuum at locality was -8.05 m, much greater than the design value (-4.18 m) used. In 1983, field tests were carried out in this plant and showed that: a) the intake pipe was gas-proofing and the total head loss was only 0.43% of the plant head, with a comprehensive loss coefficient of 0.17*, less than that of a gated intake; b) during self-priming, the instability of the unit output in a short time gave no affect on the operation of the grid and the vibration of the penstock, including the open-supported intake section, was slight, with a very short duration.

This siphon-type conduit system was designed with two vacuum pumps with a capacity of 8 liter/s ($28.8m^3/hr$) each. During acceptance testing, the priming time, exclusive of the time for pre-filling the conduit, was 15 - 20 minutes, and the priming process was recorded as shown in Fig.6. As shown in the figure, in the initial stage of pumping, the vacuum rose up quickly (in other existing plant and in the model tests, the priming process had the same rule as in the figure, see (5)) and the relative vacuum reached to 90% within 9 - 10 minutes and rose up slowly afterwards. In 1981, priming test of combination type was carried out by the plant operator to accelerate the priming process; in the initial stage, it was primied by vacuum pumps. As soon as the relative vacuum rose up to the deflection point tm as shown in Fig. 6, open the wicket gate and let the unit be partially loaded, to accelerate the priming by self-priming in the later stage. This combination-type priming could be finished well within 10 minutes. In 1983, a self-priming test was carried out by the operator. Although it was in the dry season that the natural inflow was about 3m^3/s only enough for starting one unit, the self-priming also succeeded, with slight instability of the unit output and unnoticeable vibration of the penstock. The self-priming could be finished within 5 minutes, and afterwards, it was used by the plant operator to save the plant consumption. Practice also showed that a shut-down of less than 12 hr could keep the conduit full, without the need of priming for the next loading-in of the unit.

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* This coefficient of Dishan hydro plant (Fig.2) was 0.25 in the model test and 0.22 in the field test.

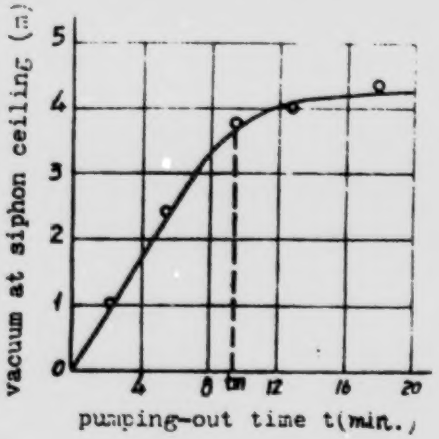

Fig.6 Priming process by vacuum pumps

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Manufacture of Pelton Wheels by the Lost-Wax Method

By
J.S. Gho

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PELTON WHEELS MANUFACTURE BY LOST WAX METHOD

BY JAVIER S. GHO (TEKHNE)

(1) A thousand and fifteen hundred (1500) years ago the Quimbaya Culture (2) manufactured theirs jewels by lost wax method. The virgin bees wax it is molded by hand, taking advantage of its low point of softening, to make the jewels in positive.

(3) As molding materials it was used a mixture of sand and fuller's earth.

(4) A sample of great beauty and quality of this metallurgical process is exposed in The Republic's Gold Museum in the city of Bogotá, Colombia.

(5) In the principal vault it is possible to apreciate the diverses objetcts manufactured in gold.

(6) But, also it is possible manufacture turbines by the same method, such is the case that we will see in the manufacturing of Pelton Wheels.

(7) To make the wax bucket mold we will use a small box with mobile bottom in which is made an incision to dispose the patron bucket, manufactured in a hand material.

(8) Using children's plasticina must be refill the patron bucket and put it over the displacement bottom, to place betwen the mold and this, a mica also with the incision at the same place and position that it was made in the wood.

(9) Once removed the excess of plasticina, the inferior mold is besmeared with vaseline.

(10) Then it is emptied the superior mold. The gypsum is type fourth (IV) or Vellmix, the same one used by dentists

(11) once separated the wood's box

(12) and separated the half parts, is extracted the bronze patron bucket.

(13) Several same type molds are made, which must be always moist to be employed.

(14) The wax mixture used is:
Virgin Wax, forty percent (40%)
Carnauba Wax, five percent (5%)
Solid Paraffin, fifty percent (50%)
Arabig Gum (powder), five percent (5%)

(15) Wax point of fusion is in the range of sixty five and seventy degree (65 to 70*C) and it is heated in a electric kettle with changeable resistance, which permit monitor the temperature.

(16) The wax emptied is done with a little aluminum container, in a continuos way until the mold it is fill completely.

(17) Once cooled, both halfs are taken apart.

(18) The buckets it must has a good superficial finished without the presence of wrinkles or streaks that come out meanly by wax low temperature.

(19) The rest of molds used are the turbine central mass.

(20) And a hollow driving rod it permited, when melted, the emptied of aluminum.

(22)
(23) In the assembly the two pieces wood mold is used.

(24) In which will be ordered around the central mass the buckets,

(25) which are supported in the wood mold inferior plate

(26) later are displace until the tin plates tops

(27) and are weld with the help of an electric welder with a cooper wire flattened on its end

(28) so, bucket by bucket they get install in a symmetrical way.

(29) After being welded, the turbine is taken out from the wood mold.

(30) Then the driving rod it get together with the central mass and it is submerged in a water detergent

(31) with the same dentist gypsum of twenty percent (20%) by weight, washed sand and refined in sifter forty to eighty percent (40 to 80%) by weight it make the mixture for the mold in

(32) negative of final founding.

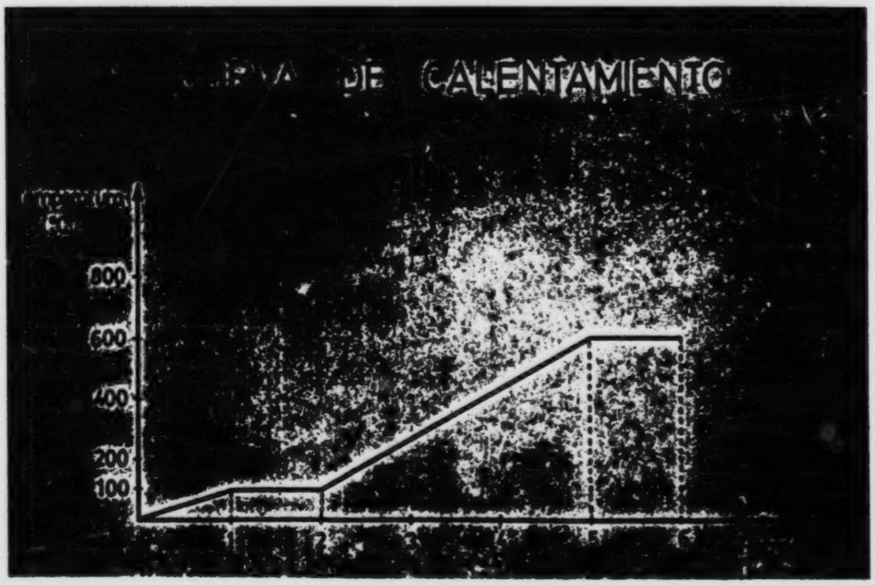
(33) Turning smoothly to take out the air bubbles, the turbine it is introduced on the mold.

(34) Looking after not to touch the can's bottom neither it remain off the center.

(35) In a pail it is turned around the mold and with an electric resistance it is generated steam to melt the wax.

(36) In an oven it is heat the remainder wax

(37) according to heating curve in the figure.



(38) Melting metal can be done in a mechanic workshop, with rudiment foundry.

(39) Using scrap aluminum

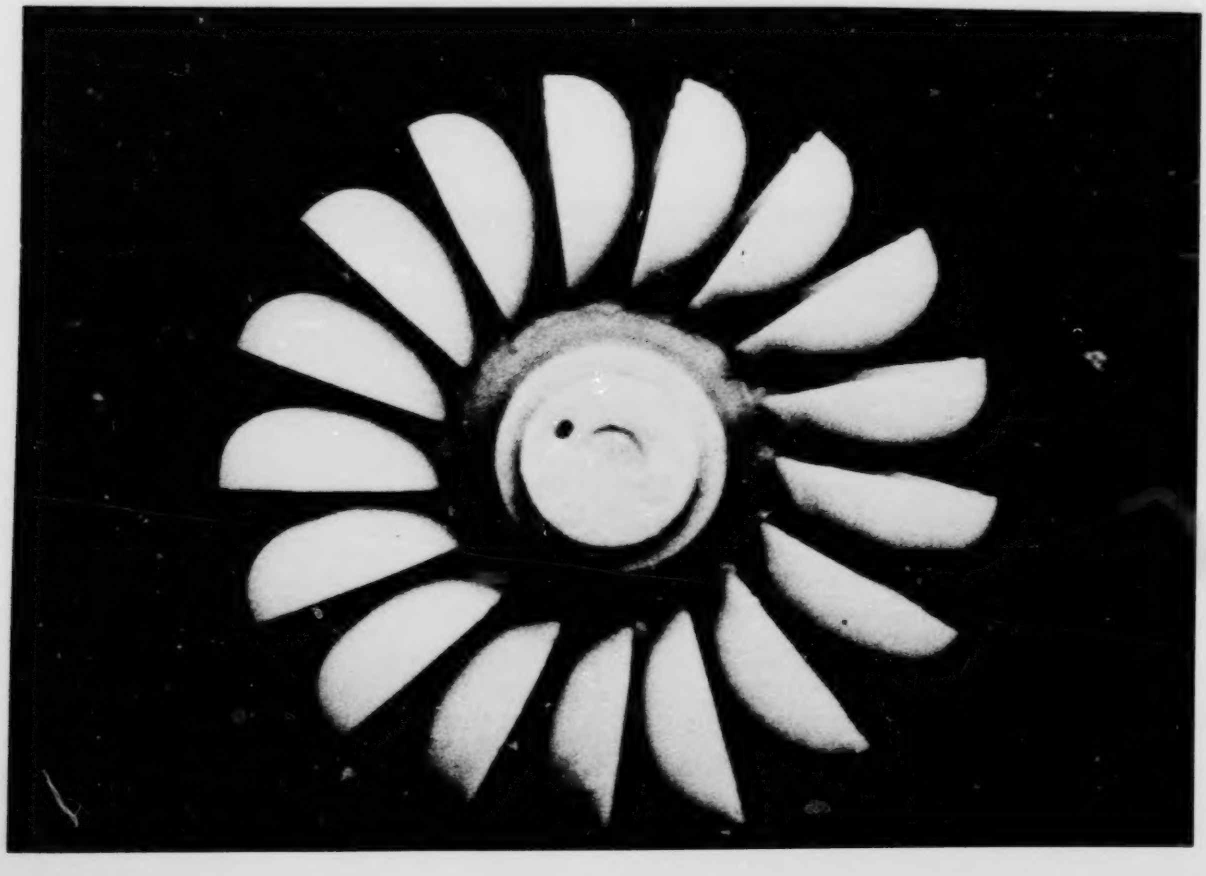
(40) it must be centrifuged to do the metal cast.

(41) Installation can be of a jet

(42) two jets

(43) tree jets

(44) four jets.



SESSION 23:

OPERATION AND MAINTENANCE

Chairperson: M. Wilson
Barber Turbine Ltd.

Worst Case Scenario Considerations in Small Hydroelectric Project Design

By
G.W. Miller, L.E. Sproule, M.R. Nandagopal

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WORST CASE SCENARIO CONSIDERATIONS IN SMALL HYDROELECTRIC PROJECT DESIGN

by

George W. Miller, P.E.; Leon E. Sproule; and
Mallur R. Nandagopal, Ph. D., P.E.

[ABSTRACT:

In the early hours of May 20, 1986, a lightning strike induced a fault on the 13.8 kV interconnecting line leading from Upriver Dam Hydroelectric Project to the Beacon Substation in Spokane, Washington State, and caused all the five hydroelectric generators to shut down. Eventual results of this major fault prevented quicker action to control the water level and the washout of the project embankments occurred. This worst case scenario was never previously forecast to happen by anyone including the engineering consultants who designed an additional powerhouse that was completed barely two years earlier. The accident brings to light how important it is for the designers to mold together all aspects of engineering - civil, electrical, and mechanical - in the design of a project which could survive the worst possible case, howsoever unlikely to happen. The accident further illustrates how the operation and management philosophies may influence or contribute towards such an accident. Engineering design teams who are more and more being employed to add bits and pieces to an existing project should first concentrate on the overall integrity of the project system including the additions to absolve themselves of subsequent liability.

The paper will describe the accident in brief and dwell on the rehabilitation work. However, major emphasis will be placed on the outlook of the accident as lessons learned. Anatomical analysis of project failures provide a great public benefit if lessons learned are taken advantage of in the future design/operation of such projects. Major factors discussed are: (i) Time-factor analysis to determine the available reaction time if the total flow is blocked should be a major engineering consideration and the analysis should be followed by sufficient freeboard design; (ii) In the operation of the project all possible emergency scenarios should be considered to develop an emergency operating procedure; (iii) Further, operator training and establishing management priorities is an important feature in thesafe operation of the project.]

1.0 Introduction:

Project failure is an essential tool for progress. Little is learned from successful projects, and as regretable as they are, failures provide the learning ground. Yes, there comes a time in the life of every project - a time to shoot the engineer, a time to criticize everyone and every agency involved. However, if a loss is to be reconciled on the balance sheet of public benefit to loss, everyone and every agency involved must be open for criticism when justified, and accolades as they are called for. Each should do their part in making adjustments to the policy, procedures, instructions, attitudes and future designs as far as they are justified.

Hydroelectric project failure during flood conditions is not very uncommon. For example, Tieton dam failure in the State of Idaho, USA, is an example when regulatory agencies started looking into safety of dams and stability of dams during probable maximum flood conditions. However, a washout occuring at normal flow conditions, as that which happened on May 20, 1986, at the Upriver Dam Hydroelectric project in Spokane, Washington, USA, is a rare phenomenon and not much thought is given towards such potential during design, operation, or inspection. It is the purpose of this paper to discuss not so much the reasons for the accident, but to disseminate the lessons learned.

2.0 The Accident:

On May 20, 1986, at 1:16 a.m., a freak thunderstorm followed by lightning opened many tie-in circuit breakers at the substation, interconnecting the Upriver Dam Hydroelectric project with a local electric power utility. The hydroelectric project situated within the east city limits of Spokane is a low head small hydroelectric project. Maximum head for generation is in the order of 10 m. The dam across the Spokane River is a concrete gravity dam with eight tainter gates and is only about 75 m. in width. In 1983 the dam was modified by the addition of 0.61 m. extensions to the top of the gates in anticipation of raising the forebay pool level sometime in the future. In 1984, a second powerhouse with 2 units was constructed and the project capacity was more than quadrupled from the original capacity of 3.9 MW of all 3 units that existed in powerhouse #1 since 1936. This also increased the utilization flow capacity from about 70 cubic meters per second to over 210 cu. m. per sec. On May 20, 1986, just before the accident, the flow was in the order of 250 cu. m. per sec. and all the five units were generating a total of 15.5 MW. A general layout of the project features as they existed at the time is shown in Exhibit 1. A one line electrical schematic is shown in Exhibit 2.

The outage at the tie-in utility substation caused all generators to shut down. The sudden trip-out most probably caused the tripping of 52 MB main circuit breaker in the switchyard connecting the utility distribution line. The turbine wicket gates closed, and the total flow passing through the five units at the time was totally stopped.

The operator on duty notified his supervisor and "routinely" proceeded to get the plant back on line and resume generation. He was not alarmed by what had happened, and thus starting the emergency generator was not his initial direction. The operator had in the past experienced the plant being knocked off-line. Therefore, the emergency nature of this was related to lost generation if the plant was not quickly put back on line as opposed to the thought that the plant itself was in jeopardy by the lack of station service power to open the spillway gates.

In the meantime, the forebay level started raising and within about a half-hour overtopped some low level embankment areas. Eventually, the overflow caused severe breaching of the embankments on either side of powerhouse #1. About three hours later, failure of the embankments occurred. Hitherto, this type of eventuality had not been foreseen by anyone. In hindsight, this proved to be a grave mistake.

The operator's initial assumption that his situation at hand was "routine" had caused him to consume precious time. One by one he kept discovering tripped protective devices and open circuits he had not anticipated, as his efforts to get back on line kept failing. He, nor the other plant personnel, had never before experienced such an extensive tripping of devices all at once. Nor was there a monitor in the system which could have provided the operator the status of these devices.

By the time the operator realized that the task of getting the plant back on line could not be achieved in a timely manner, much time had been consumed. The plant was now in grave danger. Realizing this, the operator proceeded to start the emergency generator in order to raise the dam spillway gates. The emergency generator was balky but finally started. However, there was no power to the dam. Additional checking discovered that the automatic transfer switch had no voltage and had failed to function. Presumably water, due to the overtopping, had by now entered the electrical system shorting out the automatic transfer switch, which itself had not always been reliable in the past.

By this time it became too late to save the project. Upriver Dam Hydroelectric Project was to experience the horror and devastation of a project failure.

The next task, then, was to undertake emergency measures by hand-cranking the spillway gates open, constructing a cofferdam redirecting the river flow back through the open spillway gates and into the proper river channel, and then securing the project from further damage.

Once the emergency measures had been accomplished and the project secured from further damage, the City initiated an investigation into the cause/causes of the project failure. The City made it clear early on that this was not to be a forensic investigation and that there was no desire to place the blame on anyone for the failure. This was seen as necessary in order to assure all parties associated with the project that they could speak openly, freely and candidly without fear of incrimination. The need, as the City viewed it, was to determine the facts associated with the failure and to be assured that the project flaws which caused the project failure were identified and eliminated during the reconstruction of the facilities.

Furthermore, worst case scenarios were considered in order to be assured that all reasonable measures were incorporated into the project redesign.

If on the night of May 20, 1986, the operator on duty had immediately started the emergency generator and lifted the gates, the washout would never have occurred, and the difficulties that were so apparent after the accident would never have been brought to light.

The investigations revealed project flaws that can be broadly classified into three main categories - Design flaws, Operating problems, Managerial priorities. Each of these, with emphasis on general applicability, will be discussed.

3.0 Design Problems:

At Upriver Dam, a new powerhouse was added on in 1984. The project capacity was increased from 3.9 MW to 17.7 MW. The project freeboard requirement for the increased flows, the paralleling of all generators, the reliance on one point of transfer of power to the utility lines, and the extra extension to the spillway gates have all come under focus.

3.1 Freeboard:

Freeboard refers to the difference in elevation of the lowest point in the project embankment and the elevation of the maximum operating forebay pool.

As aforementioned, the spillway dam was modified by the addition of 0.61 m. to the top of the spillway gates. The effects of the addition to the dam gates had been examined from the standpoint of the structural loading of the spillway dam to safely handle the additional head of water. The structural analysis concluded that the dam could indeed sustain the additional head. However, what was overlooked was the effect this modification would have on the project as a whole. What about the embankments? What about project freeboard and the effect on reaction time during an emergency? The addition of 0.61 m. to the dam gates then placed the top of the gates at approximately the same elevation as the low points of the project embankments. Essentially, any freeboard the project had prior to the modification was eliminated by the modification to the dam.

Adequacy of the freeboard has to be examined in terms of available response time to open spillway gates during an emergency. The relationship, of course, is the response time available upon a flow condition change causing a rise in the pool level until damage commences due to breaching. Generally speaking, for hydroelectric projects, the change in flow is assumed to be a full load rejection of all units simultaneously and represents the total hydraulic capacity of the plant's turbines.

In the case of Upriver Dam, the adequacy of freeboard dramatically changed once the new powerhouse went on line in 1984. An analysis was not done relative the effect the additional hydraulic capacity had on the project, and, therefore, proper necessary measures were not taken. These measures should have included an examination of the projects embankments to identify breach-points, possibly a modification to the project embankments to provide additional freeboard, and calculating the available reaction time the operator must deal with during a full load rejection of the project which is considered a worst case scenario.

Had the City realized the time elements involved, proper procedures could have been established for the operator to follow towards protecting the project.

The hydraulic capacity of the powerhouse constructed in 1936 is 70 cu. m. per second. Once the new powerhouse went on line in 1984 the hydraulic capacity of the plant increased to 212 cu. m. per second, or 3 times the previous capacity.

The dramatic change in available reaction time, without realizing the change occurred, illustrates why the project operated without major incident since 1936, then failed less than two years after the new powerhouse in 1984 went on-line.

When the project was rebuilt, adequate freeboard and a fuse plug, for further assurance, have been incorporated. The fuse plug limits the next breach area should a future accident occur.

The lesson, of course, is to examine the entire project for possible impact of a proposed modification.

3.2 **Electromechanical:**

In 1984, when the new powerhouse was constructed, it was determined to be economical to have one point of power transfer to the utility line. As the one-line diagram indicates, the three generators in powerhouse #1 generating at 2400V were tied to the switchgear bus in powerhouse #2 at 4160V through a transformer and a tie-in breaker (52 T). The main transformer which boosted the voltage from 4160V to 13.8 kV line voltage, was carrying the total load for the project.

Questions arise as to why the circuit breakers 52MB and 52T both tripped when 13 TO 9 in the Beacon Substation first tripped. Sequence of events indicate instantaneous overcurrent relays on all the three phases tripped 13 TO 9 tie-in breaker. After six minutes, 13 TO 9 was closed. However, 52 MB had tripped and so the station power was not restored.

A SCADA (Supervisory Control and Data Acquisition) System might have recorded the sequence of events as they occurred the morning of May 20, and, thus, provided the necessary ingredients to examine the apparent flaws of the protective relaying system. However, no SCADA System existed. Therefore, we are left to theorize and speculate as to why so many relays tripped that morning.

It is recommended that the engineer examine his electrical system design to assure that the protective relaying will function as intended. He should examine the system in terms of possible switching transients which may take place resulting in current surges, voltage spikes and frequency shifts. These can occur and should not be overlooked.

Another major design shortcoming was the lack of control board/status indicator in the control room. Examining the sequence of events at the utility substation, it was found that 13 TO 9 breaker at the substation was closed in about six minutes after the tripping. However, the operator was not aware that the line had been re-energized even a half-hour later.

Also, during rehabilitation, many problems in protection relay wiring schemes were discovered and corrected. Coordination of protective apparatus seemed to be lacking.

During the investigations, it was determined that the settings should be such that the hydroelectric generators go to speed-no-load whenever a fault external to the system occurs. This will continue the station service electrical power to operate lights and auxiliary equipment.

In the rehabilitation process, the two powerhouses have been connected to the utility line separately. Further, all unit controls have been modernized to provide the capability to adjust to speed no-load and thus continue to supply station service power in case of external faults. Exhibit 3 shows the electrical schematic of the rehabilitated project.

Mechanically, only one unit in powerhouse #2 sustained damage. A wicket gate servo motor sustained a bent piston rod. Additionally, all wicket gate shear pins were broken. Exhibit 4 shows the failed condition of the wicket gate mechanism. Why the damage occurred in the first place remains a mystery.

The turbine manufacturer reexamined the design stresses and decided to increase the factor of safety. A new design for the servo units was prepared and parts were furnished by the turbine manufacturer. The piston rod diameter was increased from 50 mm to 80 mm; the rods were heat treated to enhance physical properties; stops were installed on the wicket gate arms to prevent overtravel; and provisions were incorporated for anti-lift "holder" guides on the operating ring to prevent vertical movement. These enhancements were done for both units.

The addition of the wicket gate arm stops is important to note in that the loss of a shear pin allowed the free wicket gate and arm to move into positions which interfered with adjacent wicket gates. The result then lead to all wicket gate shear pins being lost ensuing in a runaway unit. Designers need to examine their wicket gate mechanism design in terms of the loss of a shear pin and a resulting free travel of the wicket gate and its arm.

4.0 Operations and Maintenance Problems:

City of Spokane Department of Water and Hydroelectric Services primarily is a water utility and the hydroelectric plant supplements the water utility revenue. Until early 1980's, only the one powerhouse and a few water pumping stations and reservoirs were controlled and monitored at the Upriver Station.

Expansion in the system by adding a second powerhouse, and installing a computer based Supervisory Control and Data Acquisition System were major technological changes. Job requirements of the operator dramatically changed as modernization of the plant was implemented. Training was inadequate for this change.

Operations should consider two aspects: Normal conditions and emergency conditions. The operator, due to his normal routine for the day-to-day operations, becomes quite well trained to cope with most situations encountered under normal operations.

However, emergency planning requires careful thought. What makes emergency planning so difficult is a tendency to develop a false sense of security. Emergencies often happen infrequently and, with a bit of luck, the emergencies are coped with and overcome as they occur. So why bother with a plan? Why bother with envisioning the host of emergency scenarios which "might" develop when in the end, most probably, they will be ruled as being "too improbable" to consider seriously, if at all? This, in general, was the situation at Upriver Dam. Other than what was required by regulatory agencies, no further effort insued.

An emergency plan was developed to meet regulatory requirements. Most of the emergency plans foresee only one scenario, i.e. flooding and washout due to a probable maximum flood. For small dams like Upriver Dam, the flood situation is not the greatest threat - in fact, the dam will be submerged and washout will have no incremental effect downstream. The worst case scenario is a sunny day failure - i.e. failure of the dam at low flows.

The plan proved to be of little value. It lacked sensitivity to the various possible emergencies which might occur. It lacked direction as to the proper procedure(s) necessary during an emergency.

The point here is that a serious attitude needs to be developed when preparing an emergency action plan. Care is essential in developing the emergency scenarios so as not to overlook potential emergencies nor wrongly rule out those because of a misjudged assessment of potential.

The program for the emergency action plan should include:

1. The Manual - A manual with a description of the various emergency conditions as well as clear procedures and instructions the operator needs during an emergency should be readily available. Of course, a proper notification procedure needs to be included.

2. Emergency Equipment - The appropriate emergency equipment, generally including an emergency standby generator, must be available. In the case of Upriver

Dam, the emergency generator and transfer switch is now designed for automatic operation in case normal station service is lost so that in an emergency, when the operator may be under stress, lighting and power to the dam gates are maintained.

3. Maintenance - Maintenance of the entire plant must be kept at a high level in order to minimize unscheduled down-time. Particular emphasis is needed for the maintenance of emergency equipment.

   For all practical purposes, the emergency generator at Upriver was well maintained and had been tested some weeks prior to the washout. However, what was not anticipated was a failure of the transfer switch the morning of May 20.

   Maintenance of emergency equipment should be logged or documented so that assurance can be provided to the proper authorities that the equipment is available at all times in the event of an emergency.

   Additionally, the documentation will serve in the future as evidence that a piece of equipment needs to be replaced due to increasing costs or problems with reliability.

4. Testing - All emergency equipment must be periodically tested. Again, documentation should be maintained certifying when and by whom the equipment was tested.

   In the case of Upriver, the emergency generators are now designed to be automatically exercised on a weekly basis and thus provide evidence that the equipment is functional and ready.

5. Communications - For an emergency action plan to work effectively, equipment must be readily available so the operator can call for help as well as communicate with responding personnel, personnel on site, and other parties whose actions have vital effects on the emergency. Additionally, backup communication systems are advisable in the event the primary system goes down or is not available.

   On the morning of May 20, the plant superintendent was notified early on of the power failure at Upriver Dam. The plant superintendent dressed and proceeded to the dam in his private vehicle which had no two-way radio equipment. Once the superintendent was in his vehicle he became totally out-of-touch as he drove the 45 minute trip to the project. In the meantime, the situation was getting progressively worse. Not only was the superintendent unaware of the urgency at hand, the operator had no way of conferring with the superintendent for advice and direction.

In the meantime, other personnel had arrived at the project. By the time the superintendent arrived, the people at the site had separated and became isolated from each other. No means of communications (radio equipment) existed so the superintendent could direct efforts to those at the site. The situation became a total frustration to all involved.

During the reconstruction of the facilities, telephones were installed at various location, including at the dam which is located approximately 1/2 kilometer from the control room, so that the operator is always within a few minutes walking distance to a telephone. Additionally, multichannel, hand held two-way radios were issued to the project to augment the base station in the control room. The superintendent was issued a City vehicle with a multichannel, two-way radio which he now drives to and from work. The superintendent can now maintain radio contact with Upriver Dam while responding to future emergencies. The multichannel radios also have the local utility frequency so that during emergencies the City and the utility can keep in touch and better coordinate efforts.

The lack of adequate communications, when coupled with insufficient operator training, further complicated the developments occurring the morning of May 20.

6. Training - Obviously, a plan will not work smoothly, particularly during time of emergency, if the personnel are not well trained. The personnel need to be trained in all tasks and procedures he must undertake while responding to an emergency. The training should include the manual starting of all automatic emergency equipment. Periodically emergency situations should be staged in order to allow the personnel to practice the procedures. It is one thing to start a generator under normal conditions and all together different to start it in an emergency while under duress. All emergency scenarios should be discussed with personnel. The probable results of failing to control emergencies should be discussed so that the plant personnel have a better feel of the "big picture" and hopefully develop a serious mental attitude towards their responsibility.

5.0 Managerial Priorities:

Generally, management looks at augmenting the revenue and reducing the expense. For City of Spokane water utility, the hydroelectric project is a revenue producing project. With a contract to sell/exchange power to the local electrical utility, the rate is fixed. Augmenting the revenue in this case means only to generate as much as possible without idling the generator. On May 20, 1986 the river flow was almost optimum and all five units were running. The first priority was to find what was wrong and get back to generation. Thus some time elapsed which, later on, lead to the catastrophe.

The second aspect of controlling the expense plays an important role in the budget process for replacing equipment. Is the replacement needed just because the equipment is old? The 30 kVA emergency generator was an army surplus. The generator and the transfer switch were well maintained and were useful. Without considering the worst case scenario as to what might happen, it was difficult to consider replacing workable equipment. However, this accident gave a warning that a different meaning to "justification" is necessary to replace an equipment meant to be used under emergency conditions.

It is important to note that a large percentage of project failures, attributed to operation mis-judgement, have occurred on the graveyard shift. Human metabolism does not adjust to shift rotations easily. A sort of complacency develops due to day-in and day-out routine work and when an unusual incident happens, it is difficult to see what should be done. It should be management's priority to see that the operators are well trained and exercised to meet the emergency - in army terms, it is called situational testing. To train an operator under such conditions, the operator should be made to understand what will happen as a result of his actions/inactions. His knowledge must extend from the water end of the plant to the communications.

6.0 Conclusions and Lessons Learned:

The washout incident at this small hydro project, Upriver Dam, is a blessing in disguise to many such projects throughout the world. The incident has taught us that nothing is impossible however remote a chance it has. The emergency action plan should visualize the ultimate consequence and clearly delineate the procedures to be taken. It needs to be management's priority to keep the operating personnel well trained and ready during emergency. It is the operators' responsibility to understand the consequences of his inaction and never to develop complacency in the system.

The project's system design should be examined so the plant's characteristics can be addressed in the emergency action plan providing the operator the means to deal with the emergency and "purchase" sufficient time for key personnel to arrive with assistance. Further, one needs to assume that the emergency will occur when minimal staff is on duty - such as the graveyard shift. It may be necessary to modify the project's system design if the emergency action plan cannot, by itself, "purchase" the needed response time.

It is the engineers' duty to make a thorough study of the system as a whole, to advise the management of its prerogatives and to get the operators to discharge their responsibility.

As a final note, after the accident, it occurred to the City that jeopardy exists for the project by the acts of man as well as the acts of nature. We feel it prudent that possible acts of sabotage, vandalism, and malicious acts of man be not ignored. The City is incorporating security measures into the plant's reconstruction to minimize its vulnerability from man's mischievous activities.

7.0 Acknowledgement:

The authors are indebted to the management, particularly Mr. Irving Reed, Manager - Engineering Services, for creating a rehabilitation task force and delegating responsibility. This approach provided for fast action and the project was restored in record time. The task force was spearheaded by Mr. Glen Yake who had earlier retired as Manager - Engineering. He motivated everyone in the team including the consultants and the contractors by his sound judgement and early actions.

Authors' Biography:

George W. Miller, B.S. in Mechanical Engineering from the University of Idaho, has been with the City of Spokane for over twenty years. He is now the Supervisory Engineer for the design team and he was the Project Manager for the rehabilitation of the hydroelectric facilities. Earlier he was the Construction Manager during the construction of Powerhouse #2 with two new hydroelectric generating units.

Mallur R. Nandagopal, Ph.D in Electrical Engineering from Indian Institute of Science, Bangalore, has been with the City of Spokane for over ten years. He is now the Senior Engineer and was in the task force for the rehabilitation of the hydroelectric facilities. Earlier he was the planning engineer from the concept stage for the expansion of the hydroelectric facilities.

Leon E. Sproule, B.S. in Mechanical Engineering from South Dakota State University, has been with the City of Spokane for over six years. He is now the Superintendent of the hydroelectric facilities and he was in the task force for the rehabilitation of the hydroelectric facilities. Earlier he was in charge of start-up and testing of Powerhouse #2 units.

UPRIVER DAM

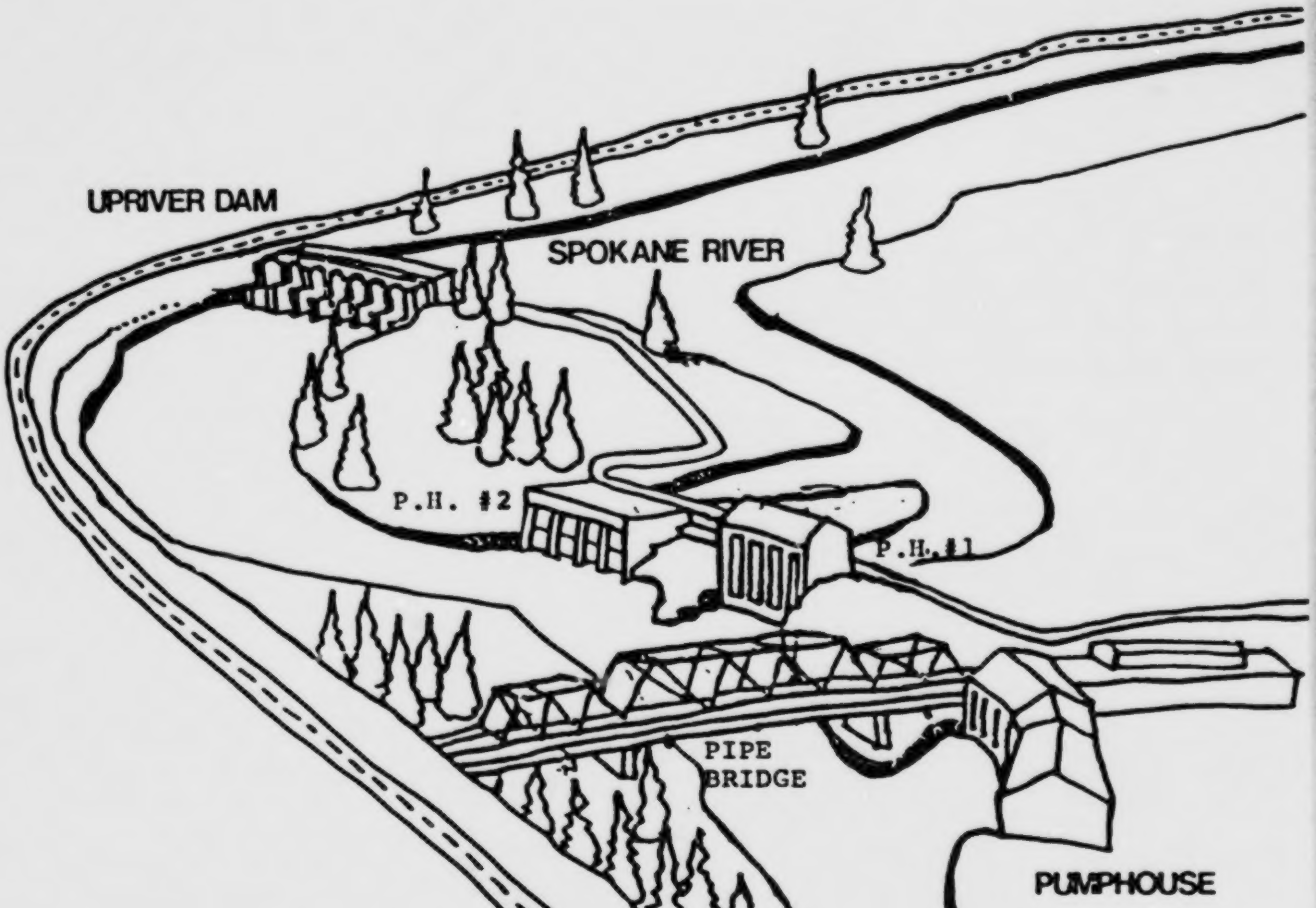
UPRIVER DAM
SPOKANE RIVER
P.H. #2
P.H. #1
PIPE BRIDGE
PUMPHOUSE

EXHIBIT 1:

PROJECT FACILITIES
BEFORE WASH-OUT

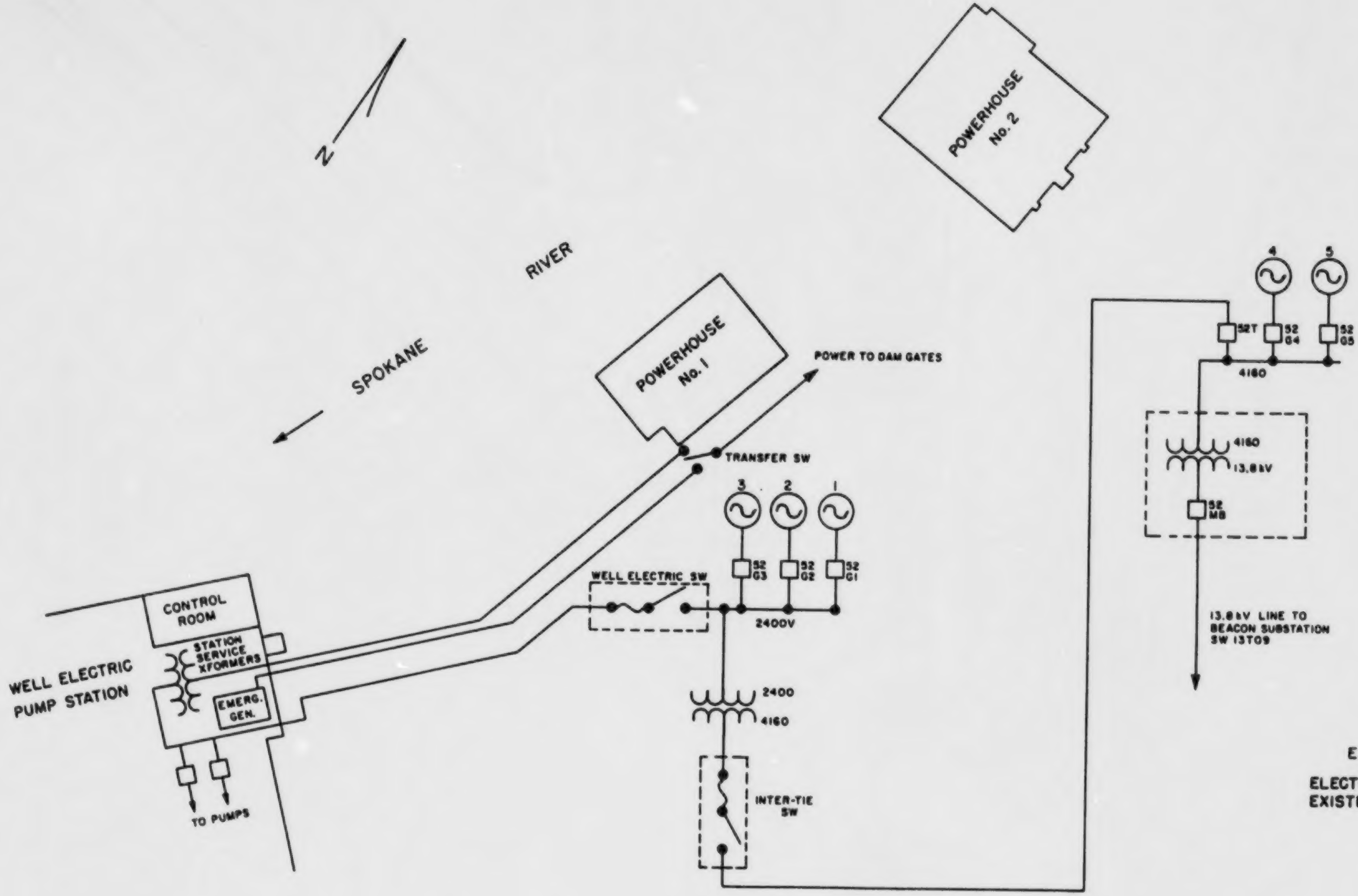
N
SPOKANE
RIVER
POWERHOUSE No. 2
POWERHOUSE No. 1
POWER TO DAM GATES
TRANSFER SW
3
2
1
52 G3
52 G2
52 G1
WELL ELECTRIC SW
2400V
2400
4160
INTER-TIE SW
CONTROL ROOM
STATION SERVICE XFORMERS
EMERG. GEN.
WELL ELECTRIC PUMP STATION
TO PUMPS
4
5
52T
52 G4
52 G5
4160
4160
13.8kV
52 MB
13.8kV LINE TO BEACON SUBSTATION SW 13T09

EXHIBIT 2:

ELECTRICAL SCHEMATIC AS
EXISTED BEFORE WASH-OUT

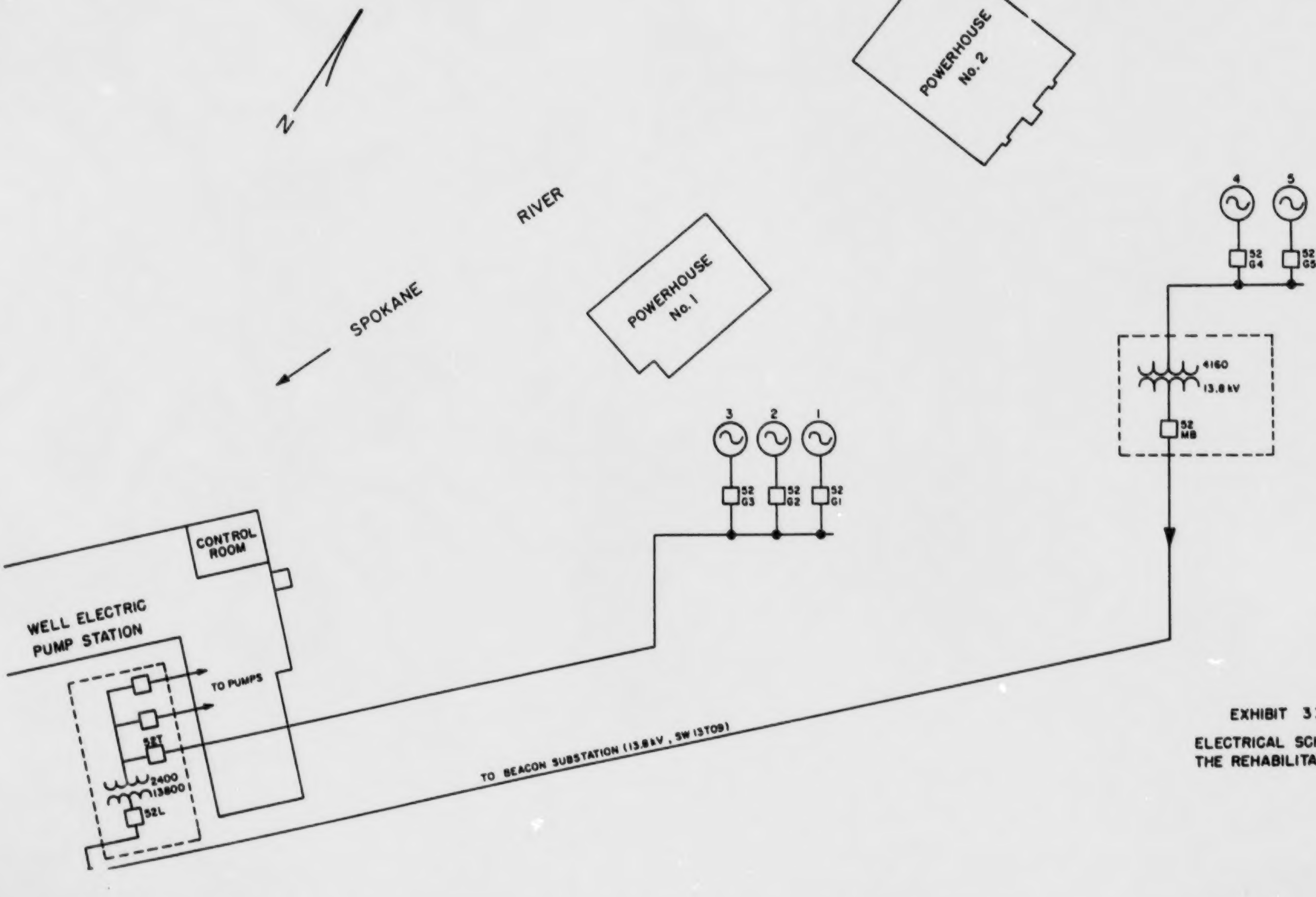
N
SPOKANE
RIVER
POWERHOUSE No. 1
POWERHOUSE No. 2
4
5
52 G4
52 G5
4160
13.8 kV
52 MB
3
2
1
52 G3
52 G2
52 G1
CONTROL ROOM
WELL ELECTRIC PUMP STATION
TO PUMPS
52T
2400
13800
52L
TO BEACON SUBSTATION (13.8 kV , SW 13T09)

EXHIBIT 3:

ELECTRICAL SCHEMATIC OF
THE REHABILITATED PROJECT

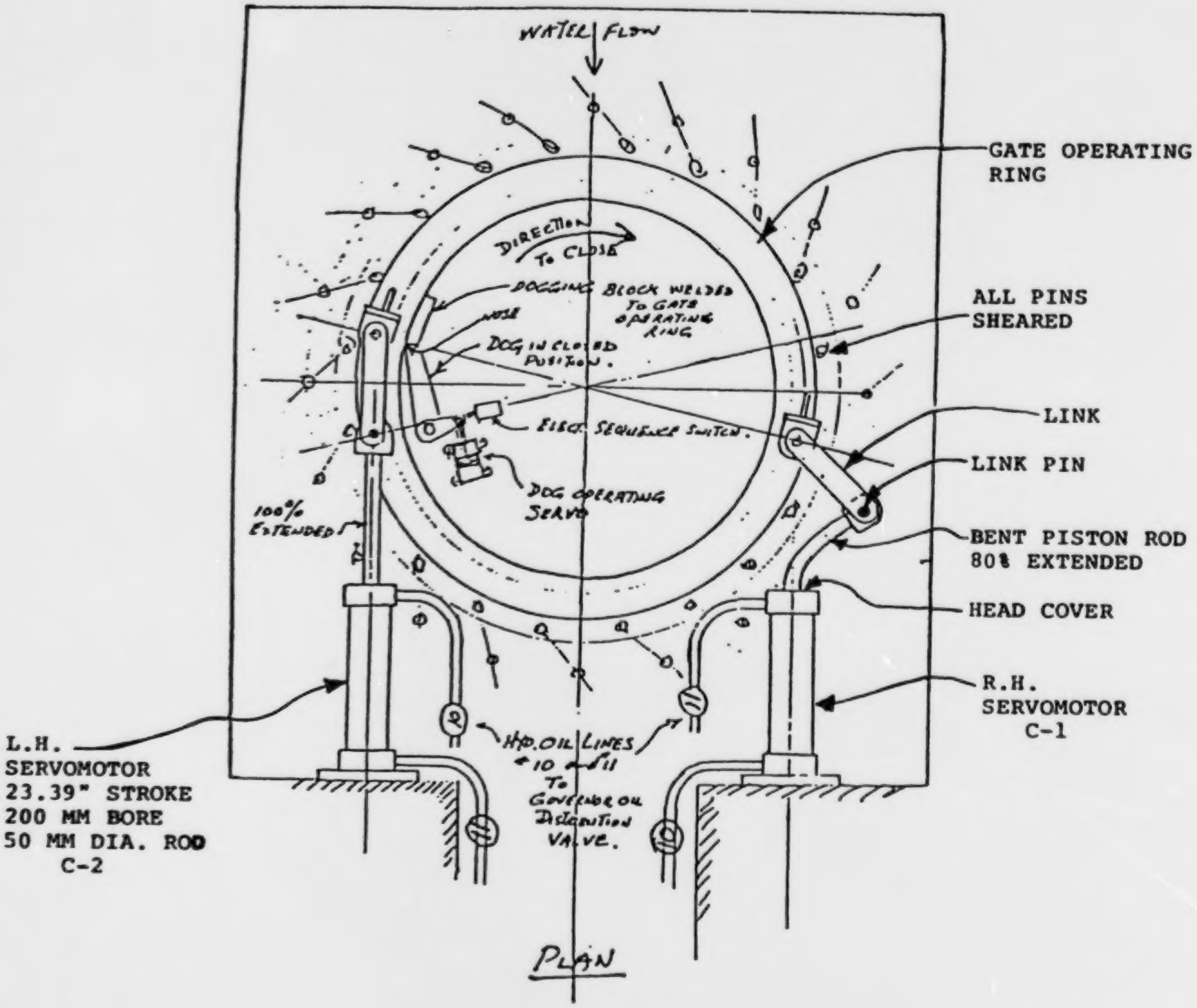
WATER FLOW
GATE OPERATING RING
DIRECTION TO CLOSE
DOGGING BLOCK WELDED TO GATE OPERATING RING
NOSE
DOG IN CLOSED POSITION.
ALL PINS SHEARED
LINK
ELEC. SEQUENCE SWITCH.
LINK PIN
DOG OPERATING SERVO
100% EXTENDED
BENT PISTON ROD 80% EXTENDED
HEAD COVER
R.H. SERVOMOTOR C-1
H.P. OIL LINES #10 & #11 TO GOVERNOR OIL DISTRIBUTION VALVE.
L.H. SERVOMOTOR 23.39" STROKE 200 MM BORE 50 MM DIA. ROD C-2
PLAN

EXHIBIT 4:

FAILED CONDITION OF WICKET GATE MECHANISM

Cold Weather Considerations

By
J. Breckon

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COLD WATER CONSIDERATIONS

by

JOHN R.BRECKOM P.ENG.
of
APPROPRIATE POWER ENGINEERING CORP.

COLD WEATHER CONSIDERATIONS

CAUSE AND EFFECT

Dams have failed, intakes clogged, penstocks burst, valves seized, turbines worn, generators shorted, transmission lines collapsed and people have been injured at hydro-power installations. The causes are often a combination of just two circumstances; cold weather, and a failure to account for it.

Cold weather affects materials people and plans. Materials, as they cool, change some of their characteristics. Water changes it's state to ice at or about 0°C (32°F); metals and plastics become brittle at lower temperatures unless specifically formulated. All materials shrink with decreasing temperature unless held from doing so. People are required to dress more warmly and usually more restrictively the colder it becomes; their field of view may be narrowed, their sense of feel is numbed, and their actions become less efficient. Tasks planned to be done easily in mild weather may become difficult or impossible to perform under conditions of cold. Hands may freeze to cold metal, concrete might not cure properly, painting or welding might require expensive and time consuming modification to complete, equipment might become difficult to operate or require to be considerably derated.

In certain instances cold and it's effects can be used to advantage. Clear, cold weather is often a good time to do trigonometrical survey work in the relative absence of heat distortion. Boggy ground can become passable when frozen, and lakes and rivers can be crossed on their frozen surfaces; even aeroplanes can be landed on the ice if sufficiently thick. Ice cover can be a convenient platform from which to drill, or do depth soundings for underwater contours.

However, cold weather effects are by and large negative in that their consideration requires the expenditure of time, effort and money not required in other less severe climates.

CLIMATE

Climate varies considerably throughout Canada. General information on anticipated climatic conditions at specific locations are usually inferred by reference to nearby or similarly oriented measured conditions of long duration. Local conditions should be noted in order to tell whether actual conditioned are as expected; if not, possible changes in operation and/or physical structure might be warranted. General information may be obtained from Federal or Provincially funded organizations operating within the various Provinces and Territories.

For example in B.C.;- Air Branch Studies,
Ministry of Environment,
Parliament Buildings,
Victoria, B.C. V8V 1X4

Requests for information are best submitted together with a sketch showing the approximate extent, orientation and location of the installation. Provincial or Federal government issued 1 : 50 ,000 scale mapping is available for most of Canada and would form a good basis on which to sketch.

Information on climate is collected on a routine or sometimes spot basis at many establishments, often by the government, but also by private companies and individuals. As a basis for comparison, any specific site measurements should be included with the request for further information.

For planning design, operation and maintenance, information on the complete range of probable and possible weather is required. Aspects particularly for considerations of cold weather are outlined in the following chart:

Type of information	Purpose
Normal and extreme air temperatures by month, length and time of record.	General appreciation of site conditions for construction and operation planning.
Minimum air temperatures, and chances of their occurrence.	Structural design. Heating & insulation considerations
Maximum expected rates of change in temperatures below 0^oC (32^oF).	Appreciation of sheet-ice induced loading.
Normal and extreme accumulated degree-days below freezing (Freezing Index).	Estimates of sheet-ice thickness.
Time and rate of snowfall.	Construction Planning.
Accumulations of snowpack.	Structural and operational design.
Normal and extreme dates of ice formation and breakup on adjacent bodies of water.	Operation and construction planning.
Wind speeds, normal, extreme and predominant direction.	Structural design. Wind induced sheet ice movement and loading.

Although information specific to the site is required, some feeling for anticipated conditions may be obtained by reference to the following publications:

Department of Mines and Technical Surveys, Geographical branch, "Atlas.of Canada", Ottawa, 1977.

Supplement to the National Building Code of Canada, "Climatic Information for Building Design in Canada".

Considerable caution should be exercised by the user of graphs, figures or tables abstracted from these types of publications for reasons which include the following:

1. The figures are obviously at a small scale, and locating a site accurately is difficult.

2. Lines drawn on the figures are of necessity very approximately located and may ignore some data. For example: mean annual snowfall at Daisy Lake Dam north of Vancouver averaged over many years of records is 400cm (160 inches), whereas one might infer 250cm (100inches) from the available figure.

3. Tables and figures are produced with some specific purpose in mind, and may not be applicable to the type of installation. For example: the National Building Code of Canada does not specifically apply to "hydro-electric dams and structures.....", but information published in it may form the basis for the design of such dams and structures if the information is modified sufficiently to account for the different consequences of failure.

FROST

Moisture present in the ground can freeze and thaw with air temperature variation, the depth from the ground/air surface at which the freezing occurs being related to the "Freezing Index", see Figures 1 and 2.

Freeze/thaw causes swelling and contraction of the ground. In generally horizontal ground the surface will rise and fall (frost heave), but at depressions or cuts in the ground surface, say at river banks, surface movement can have considerable horizontal components. A structure or building sitting on ground subject to freeze/thaw will move unless restrained. If the nature of the ground varies under a structure, say part clay and part gravel, differential movement will occur and the structure will either tip (rotate), or be considerably stressed. It is usually best to locate a structure on a uniform foundation. A free-draining ground will be least susceptible to freeze/thaw.

To eliminate movement due to freeze/thaw, structure foundations should be below the limit in Figure 2. Care should be taken that, in excavating to this depth, the exposed sides and bottom of the excavation are not subject to frost penetration which will become a problem upon subsequent thawing. Either the excavation should be made during mild temperatures, or the exposed surfaces should be blanketed by some means until the foundation is in place. Backfill in contact with such foundations should be well drained, because if the backfill material freezes to the foundation walls, it could lift and crack the walls, as well as exert pressure on them. Covering the foundation walls with a bond-breaker will help keep the movements of the foundations and backfill independent, and reduce some of those pressures. If during operation the powerhouse structure tilts, or cracks appear in the walls, or the foundation in any way appears distressed, it might require the foundations to be taken deeper, or backfill material surrounding the structure to be removed and replaced by more free draining material, and some effort made to lay drains, or provide pumping to keep the water table low.

In some locations the ground is permanently frozen to great depth, and freeze/thaw occurs only at the surface. This condition of permafrost can exist at higher altitudes a great distance south of the southern limits usually indicated. Introducing structures into such ground required special considerations.

First, the ground itself may have to be excavated by unusual methods. Heating the ground might make excavation easier, but the ground should be allowed to re-freeze before placing foundations. Frozen ground will stand unsupported at steep slopes, but the exposed surfaces must be guarded against thawing.

If heat can flow from a structure into the frozen ground where it is buried, the possibility exists of the ground thawing, and the structure either floating or sinking. If melted water can drain from around the structure, piping of the ground material, and unexpected settlement can occur. It is not possible to effectively insulate some structures, such as utility pipelines, and therefore they must be placed under ground.

COLD WATER

Pure water is densest at about $4^{o}C$ ($41^{o}F$), and dense water sinks through less dense water.

Figure 3 shows the temperature at different depths in a lake, and the changes during Fall, as the air temperature cools the surface and ice forms.

Currents will move vertically through the water as the surface water cools and sinks to it's equilibrium position. This could occur in a relatively short space of time, causing some agitation at the surface. The surface water temperature will always lag behind the air temperature until all of the water has been cooled to it's maximum density, then cooling of the surface water will be relatively rapid and ice will form.

One method of delaying the formation of ice, or slowing it's rate of growth, or thawing it, is to bring the relatively warmer water to the surface. This is done naturally by springs which occur in lake bottoms and which in certain circumstances of geothermal activity will keep ice from ever forming; or artificially, by allowing compressed air bubbles to rise through the water and literally drag up the warmer water, or by pumping the deeper warmer water to the surface.

In larger undertakings, the mass of relatively warmer water below the reservoir surface may be used to inhibit or control ice growth downstream of the reservoir by drawing it off and releasing it into the stream, in some cases allowing year-round river traffic where the river had historically frozen, or mitigating the potential hazards from the build-up, and subsequent failure, of ice dams.

ICE

When water freezes it increases it's volume about 9 percent and decreases its density by a similar amount, and therefore the resulting ice floats. In still or tranquil flow, once all the water is cooled to below 4°C, freezing occurs at the air/water surface and plate or sheet ice forms. In turbulent water, close to 0°C, where air is introduced by mixing, or where the flow path rapidly contracts and expands around obstructions, ice can form at any depth where the water becomes "super cooled" to just below 0°C. Under such circumstances "frazil" ice, which often appears cloudy under the surface, forms and readily adheres to itself or any other convenient surface. Both of these forms of ice must be considered.

1. Sheet Ice:

Once sheet ice starts to form, it will grow in thickness as long as the air temperature is below 0°C. It's maximum thickness is related to the Freezing Index at a location; and is given approximately by the formula;-

$$\text{Maximum Ice Thickness (metres)} = 0.036 \times \sqrt{\text{Freezing Index } (^{\circ}\text{C})}$$

$$[\text{Maximum Ice Thickness (inches)} = \sqrt{\text{Freezing Index } (^{\circ}\text{F})}\ ]$$

$$\text{Example: Freezing Index} = 2000 \text{ day } ^{\circ}\text{C}$$

$$\text{Max. Expected Ice Thickness} = 0.0036 \times \sqrt{2000}$$

$$= 1.61\text{m (64 inches)}$$

The rate at which ice forms increases with lower air temperature, but decreases with ice thickness. It also decreases with increased insulation of the ice surface, which could be by natural snow cover, artificially induced snow cover, or some other material covering such as straw.

As soon as it forms, ice is subject to the frictional drag of the water flow beneath it, and the air flow above it. The smoother the surface of the ice, the smaller will be those forces per square metre of surface, but considering the total surface involved, the forces can become substantial (on larger lakes many thousands of tons). These forces do not depend upon ice thickness, but their effect does if the ice is free to move. Thin ice, with less inertia, will be moved more easily than thicker, heavier ice, and will attain higher velocity more quickly. However, when it fetches up against a structure, the thinner ice will probably not exert as much impact force, as it will crack and buckle more easily. In most cases if ice forms, it is not free to move; but under certain circumstances, the ice is set free, and these forces can be brought into play.

A water intake or other structure can usually be set back from a potentially large sheet of ice, and some effort made to keep ice and it's effects from the structure by the following means:

(a) manually breaking the ice and removing it while it is still a manageable thickness if labour is available and safe access provided.

(b) using a boat to keep the ice broken, either by physically driving the boat as an icebreaker, or using the wash of the propeller to move the ice, or inhibit it's growth by washing the warmer water to the surface. Tug or boom boats, which usually have relatively deep draught are best used for this as their propellers are moving the warmer water from the greater depths.

(c) blanketing the ice with snow or straw or some other insulating material to slow the rate of growth, and keep the ice thin.

(d) introducing warm water to the surface (bubbling air, pumping water) to inhibit ice growth.

(e) directly heating the water surface using warm air blowers or infrared heaters.

(f) covering the intake area to trap warmer air.

(g) heating the surfaces against which ice would otherwise form (induction heating of metals; heating wires in concrete; radiant heating of exposed back faces of gates; passing hot air, water or oil through embedded coils or hollow sections).

(h) Using explosives, detonating underwater to maximize ice sheet uplift and promote failure in bending.

Air temperature changes will induce temperature changes in ice, and the ice, if free to do so, will expand or contract by an amount equal to: 0.00016 times any dimension for each degree Celsius change in temperature (0.000089 for each degree Fahrenheit).

> Example: 100m (328 feet) length of ice; the air temperature drops from $-5^{o}C$ ($23^{o}F$) to $-15^{o}C$ ($5^{o}F$).
>
> The change in length = $0.00016 \times 100m \times 10^{o}C$
> = 0.16m
> [or = $0.000089 \times 328ft \times 18^{o}F$
> = 0.53 feet]

A structure embedded in, or attached to, an ice sheet must be capable of deflecting sufficiently, or resisting the movement. The amount of force ice can exert under these circumstances depends upon the consistency of the ice, it's thickness, the temperature gradient through it, the rate of gradient changes (related to the rate of change of air temperature) and the amount of restraint on the ice sheet.

Sudden fluctuations in the surface of the water supporting the ice can cause large uplift or downpull on structures to which the ice adheres. Water from an unseasonal melt, or water released into the reservoir when an ice-dam gives way, could cause buoyancy forces on the ice to be transmitted to the structure.

Rapid drawdown of a pond, river or canal can leave ice hung up on the structure.

In these circumstances the ice behaves plastically, gradually deforming to regain it's equilibrium. The forces involved depend not only on the condition of the ice and the configuration of the situation, but the speed at which the events occur. Sheet ice/structure interaction is often an involved study, and if at all possible, elimination of this type of interaction usually pays.

Ice can be kept away from the structure by causing it to collect, say by means of a floating boom, upstream of the structure, or by putting a relatively weak buffer immediately against the face of the structure to absorb thermally induced forces. If a floating boom is used, careful attention should be paid to having the weakest link, should failure occur, somewhere where it can be attended to, and not on the reservoir floor.

2. Frazil Ice

Frazil ice is the ice which can form at any depth in moving water, given the right circumstances. Rivers have become completely dammed by frazil ice, resulting in upstream flooding, and when the dams break, downstream flooding.

As turbulence is a contributing factor in introducing cold to the water, one method of eliminating, or at least reducing the formation of frazil ice, is to make the water course less turbulent. Widening and deepening a watercourse would do this, as well as removing boulders and other items which cause the flow to deviate. Slowing the flow gives the ice more time to float to the surface where at least it can be seen, and possibly melted. Removing boulders or stumps or waterlogged trees from the watercourse, as well as removing potential areas of ice formation, also removes potential surface to which it might adhere and grow. Water flowing uniformly at no more than 0.6m/s (2f/s) usually does not support the formation of frazil ice within it, but one of it's forms, anchor ice, can form when there is no movement of water at all.

If frazil ice does form and floats downstream, then the intake must be planned to either exclude it or otherwise deal with it. Exclusion might be achieved by siting the intake such that the ice floats by, but the hydraulics involved must be carefully thought out so that the shape chosen does not draw in the ice, with the water. If an existing intake is already causing ice to be directed into itself, it might be necessary to build wingwalls, or some other type of structure, or to dredge out an alternate channel in order to change the unfavourable hydraulics of the situation.

If the ice is present only on the water surface, it might be caught on an upstream log-boom to be dealt with more conveniently, or deflected from the intake by means of a skimmer or obliquely angled surface extending down over the intake to a sufficient depth to account for both the water elevation changes and the thickness of the frazil slush.

Vortexing, the swirling of water around a column of air, must be especially avoided at intakes intended to operate in cold water.

Not only does the vortex speed up the water and introduce air at depth, but it also supplies the mechanism for drawing any formed ice down into the pipeline, where it becomes increasingly hard to deal with. Vortexing can be avoided either by drawing water from well below the surface, or by providing a floating cover over the intake, or providing guides to inhibit the swirling motion. In cold climates one should aim for sufficient depth of submergence as neither of the other two methods mentioned will eliminate potential ice problems.

Most water intakes require trashracks to limit the size of materials entering the water passages. The racks partially block flow, cause turbulence, and may require special attention to prevent either the formation or build-up of frazil ice on them. Various forms of heating racks, direct heating of metal racks by induced electrical current, or hot water, oil or steam passed through hollow rack sections have proven successful. Frazil ice has less tendency to adhere to wood and plastics than metals. Paints have been developed which appear to cause at least partial immunity to frazil ice build-up. Some success in shedding ice from racks has been claimed by exciting lateral vibration of the bars. This method should be applied judiciously as these high frequency vibrations will soon show up any structural or fabrication deficiencies in the racks, and will almost certainly bring about a shorter life in the bars, due to fatigue induced stress concentrations.

In view of the uncertainties with regard to the location of frazil ice formation, and the probability of a breakdown in whichever systems are put in place to handle it, smaller intake structures should be designed not to fail under conditions of full blockage. If complete blockage does occur, the design assumptions should be carefully checked to make sure a sufficient factor of safety against buoyancy has been provided, and if it has not the intake must be either be anchored down, or have weight added.

When insufficient water is reaching the turbine the cause can be investigated, but a failed intake can cause all sorts of materials to be ingested into the water system with potentially expensive consequences.

Once in a penstock, frazil ice is likely to stick anywhere along the sides, but most likely at bends, joints, couplings, inspection ports, valves and branches, where turbulence may enhance it's growth. The buoyant ice will tend to float to the top of the pipe, and collect there, blocking the air bleed and intake valves located at high points along the pipe. Other water control valves along the pipe can become locked by ice. If the pipe does become even partially blocked with ice, the water supply should be shut off, and immediate action taken to remove the blockage before it grows to unmanageable proportions, or causes the pipe to burst. How the blockage is dealt with depends very much on the type of pipe, it's size and location. If access is available at the downstream end, blowing hot air, or using a steam line against the downstream face of the ice will allow the ice to melt and run away. If the upstream end is accessible, pouring a salt solution or antifreeze solution (with due regard to it's subsequent environmental downstream effects) on top of the ice will eventually open a path. Direct heating of the outside of the pipe by hot air or by blow torch should be done with extreme caution, and gently over as large an area as possible so as not to cause local thermal stressing of the pipe.

The small nozzles of pelton turbines may be instantaneously blocked by lumps of ice, resulting in an internal penstock pressure of up to twice the static head. Other turbines are less susceptible to this from of blockage; the cross-flow types claim to be almost immune.

Frazil ice sometimes attaches to anchor or bottom ice which has formed on the river bed, and can help contribute sufficient buoyancy to lift particles from the bed, and carry them along, greatly increasing wear on penstocks and turbines. Even with the ice itself melting along the way, the particles can scour the pipes and the turbine blades at which they are directed.

Leaving the turbine, flow is often quite turbulent, and frazil ice can form in the tailrace. As with the intake, the velocity of the water should be kept below 0.6m/s (2f/s), and the flow made as tranquil as possible. It would help to enclose the tailrace, and possibly provide heating to the enclosure to move any frazil ice problem downstream of the installations.

THE WATERSHED

In many areas much of the total annual precipitation falls as snow, and is held in that form throughout the winter, until warmer spring temperatures melt the snow. The date of release of spring water may vary considerably from year to year, and plans to deal with the water should be flexible enough to take this into account.

THE DAM OR DIVERSION STRUCTURE

The structure will create a pond of water often where none existed previously, therefore creating the possibility of sheet ice formation where none was known previously. Rockfill structures are inherently massive, and may not require modifications to accept sheet ice loading, but most other types of structures must be carefully designed if such loading can occur. For relatively low dams in Canada, ice loading can exceed water loading. Especially vulnerable are 'flash board' type structures sometimes added to existing dams to increase pondage: as cold air circulates behind the boards, freezing of water adjacent to the boards is made more likely. It is prudent to maintain winter water levels below such structures, by having spill occur at a level far enough below the relatively weaker structures so that ice forming will not affect them.

Some diversion structures will be provided with low-level outlets to allow draining of the pond, and possibly flushing of it's accumulated sediments. If a valve, when activated produces a spray which can freeze, the valve should be operated judiciously during cold weather. If the plant is not intended to operated during the winter, and the intake pond is left draining, the drain should be monitored for at least one winter of operation to check the effects of the cold weather.

INTAKE STRUCTURE

The expected thickness of sheet ice may be calculated, and the intake designed to be capable of operating below the level of that ice floating in the forebay. The thickness of frazil slush which can coalesce at the surface is impossible to predict, especially if the frazil accumulates below the sheet ice. Making the pond as big as practical will encourage the frazil to surface away from the intake, where it poses less of a threat.

CANAL

A canal operating with an ice cover has different hydraulic characteristics from one with a free water surface, and account must be taken of the water friction against the underside of the ice. The walls of the canal must be capable of accepting loading from the expanding and contracting ice cover.

When the ice on the canal melts, or rather breaks up, some provision should be made at the downstream end of the canal to prevent the floating ice hampering the operation of an adjacent intake. It might be possible to flush the ice away by allowing a surge of water into the canal and ceasing operation of the plant whilst the surface ice is further loosened, then carried along and passed over a downstream spillway.

PENSTOCKS

Water passing along a pipe gains heat created by the turbulence of it's passage, but at the same time loses heat to the pipe if the pipe is colder than the water. When heat loss exceeds heat gain, water remaining in the pipe might eventually freeze. In winter operation the water entering a penstock is often just above freezing, and the rate of heat loss coupled with the time the water remains in the pipe is critical.

Heat gain through turbulence is proportional to the square of the water velocity. Heat is lost through the wall of a pipe at a rate proportional to the conductivity of the material.

Relative conductivities of various materials are:

Wood Stave	1
PVC	1
Polyethylene	2.5
Asbestos Cement	4
Concrete	5
Ductile Iron	385
Steel	420
Aluminum	1410

e.g. heat is conducted through steel 420 times as easily as through wood.

Heat is also lost from the outer surface of the pipe by radiation and convection. The relative powers of typical surfaces to emit heat by radiation are:

Aluminum	1
Cast Iron	1.7
Wood	2.2

Convection loss increases with wind velocity, by factors of 3.7, 5.1, 6.2 and 7.1 for velocities of 10, 20, 30 and 40 miles per hour, respectively, compared to 1 for still air.

Under given combinations of materials, temperature and flow rates, heat gain and loss quantities can be calculated, but the foregoing tables give some indication as to which materials and conditions will be more likely to result in the formation of ice, and which combinations should help alleviate that possible condition.

Cold weather considerations for penstocks include:

1. The higher the velocity of the water through the pipe, the greater the heat gain, and the less time the water spends passing through the pipe. Therefore in winter especially, flow through the pipe should be kept at as high a rate as possible. It is better to waste energy (or possible find a use for it) than to cut back on the flow.

2. Reducing or removing cold air movement over and around the pipe will considerably reduce both radiation and convection losses. Siting the penstock through mature woods or along some sheltered route would help reduce wind cooling effects. Allowing controlled growth of trees or bushes to shelter the pipe, or providing a fence alongside to reduce the airflow over the pipe will help. Painting the pipe a dark colour will allow the pipe to absorb more radiant energy during sunny but cold days.

3. Surrounding the pipe with an insulating material would reduce conduction losses.

4. Burying the pipeline removes air flow and introduces an insulating material, the backfill, and the possibility of further insulation through snow cover. Depending upon the terrain and nature of the ground requiring excavation burying pipeline can be an initially costly alternative, but on occasion, has been found to be the only viable alternative for year round operation. It might become the only viable alternative to maintaining operation throughout a winter for which the plant was not originally designed.

5. Air bleed and intake valves should be well insulated, possibly enclosed in removable covers. In areas of high snowfall a passage for the air should be kept open at all times because if the valve fails to operate when required, an annoying temporary plant shutdown due to lack of water could become a protracted plant shutdown due to a burst or collapsed penstock.

6. Water leakage can occur at mechanically coupled joints, and between wood staves. The pipe should be checked and leakage stopped or dealt with either by tightening the joint, replacing the seals, or insulating the leaking area and directing the leakage to where it can do no harm. Resulting ice build-up can leave the joints ineffective, or introduce some other hazard.

7. Allowance should have been made at supports and joints for the shortening of pipes due to both internal pressure and cold temperatures. If operation shows that insufficient allowance has been made, some form of sliding joint might have to be introduced into the line. Depending on the type of pipe and the system by which the pieces of pipe were joined, failure may occur at the pipe, or across a joint. Either condition has the potential of causing a washout of part or all of the facilities. Potential failure may be indicated by increasing leakage at a joint, straightening of an otherwise sagging exposed pipe or movement of anchorages. The immediate relief will be to reduce the pressure by cutting off the flow, but then care must be taken not to have the pipe shrink further due to the introduction of cold air in place of the water.

8. Pipes should be checked to ensure that where applicable they can support snow loads, both with the pipes full and under pressure, and with the pipes empty. Potential for snow impact loading from tree shedding, roof shedding, or snow slides should be removed by cutting the trees back, extending the roof over the pipe, or building a deflecting structure to channel the snow away.

9. Water passages should be drained if the installation is shut down even for a short periods during winter; the inconvenience will be worthwhile.

POWERHOUSE

The powerhouse must obviously be sufficiently strong to resist snow and wind loads. A steeply pitched roof will shed much of the snow load, but can attract increased wind load. Doors and windows should be weatherproofed to prevent blowing snow from entering the building.

Ventilation should be provided through some means which will allow continued operation in spite of snow build up. The inside of the power house should be well drained to handle leakage and condensation. The drains should be either insulated by being buried deeply, or heated either by electrical heat tracing or by direct heat. The water must leave the powerhouse, and some ingenuity may be required to prevent blockage of the outfall. One method is to bury the outfall in a well drained granular material. Condensation will form on the bare metal outside the water passages within the powerhouse, unless the surfaces are coated with particularly formulated paints, granulated cork, or some other insulating material.

To help maintain the interior temperature, leave light bulbs burning and supplement this by radiant heaters directed towards the machinery. A ceiling fan would help circulate the heated air to where it is most needed.

During unscheduled winter shutdowns secondary power sources, such as batteries or generators, should be available to prevent freezing in the powerhouse.

TRANSMISSION LINES

The lines should be located bearing in mind the possible changes to the ground profile brought about by standing and drifting snow, and sufficient clearance should be left under the lines to account for this situation. Lines should be well clear of trees which can bend and topple under snow cover. Intense cold causes the lines to contract, and sufficient slack to account for this should be incorporated when stringing the lines, or the resulting tension will pull poles out of place and strain supports. A normal 'heavy icing allowance' of 12mm of ice build up all around a cable will probably have been allowed in designing the line. In areas where build up exceeds this amount, especially areas adjacent to waterfalls where freezing spray can build up centimetres of ice, the lines should be periodically cleared, or more support added. Guy lines to poles should be made as visible as possible against the white background; split orange coloured pipe or fluorescent orange paint extending to well above the expected snow cover should be used.

PRODUCTIVITY

Owner/operators will appreciate the problems of motivating themselves to perform emergency work at '30 degrees below'; but absentee owners should realise that it is an accepted fact that labour productivity at -20°F is one quarter of that obtained in the summer months and that at -35°F or below productivity is next to zero. Therefore it would appear obvious to have the plant designed not to require routine outdoors maintenance to be done during really cold weather.
It should also be appreciated that equipment must be specially prepared if it is to operate at low temperatures, and that lifting devices may fail at loads greatly below rated capacities.

ACCESS

Safe access should be assured to any location requiring attendance during the operation of the installation. Pathways and especially steps should be adequately drained to prevent icing over, and rope hand lines should be provided where required. Trail markers should be obvious whenever they might be required, during all weathers, day or night.

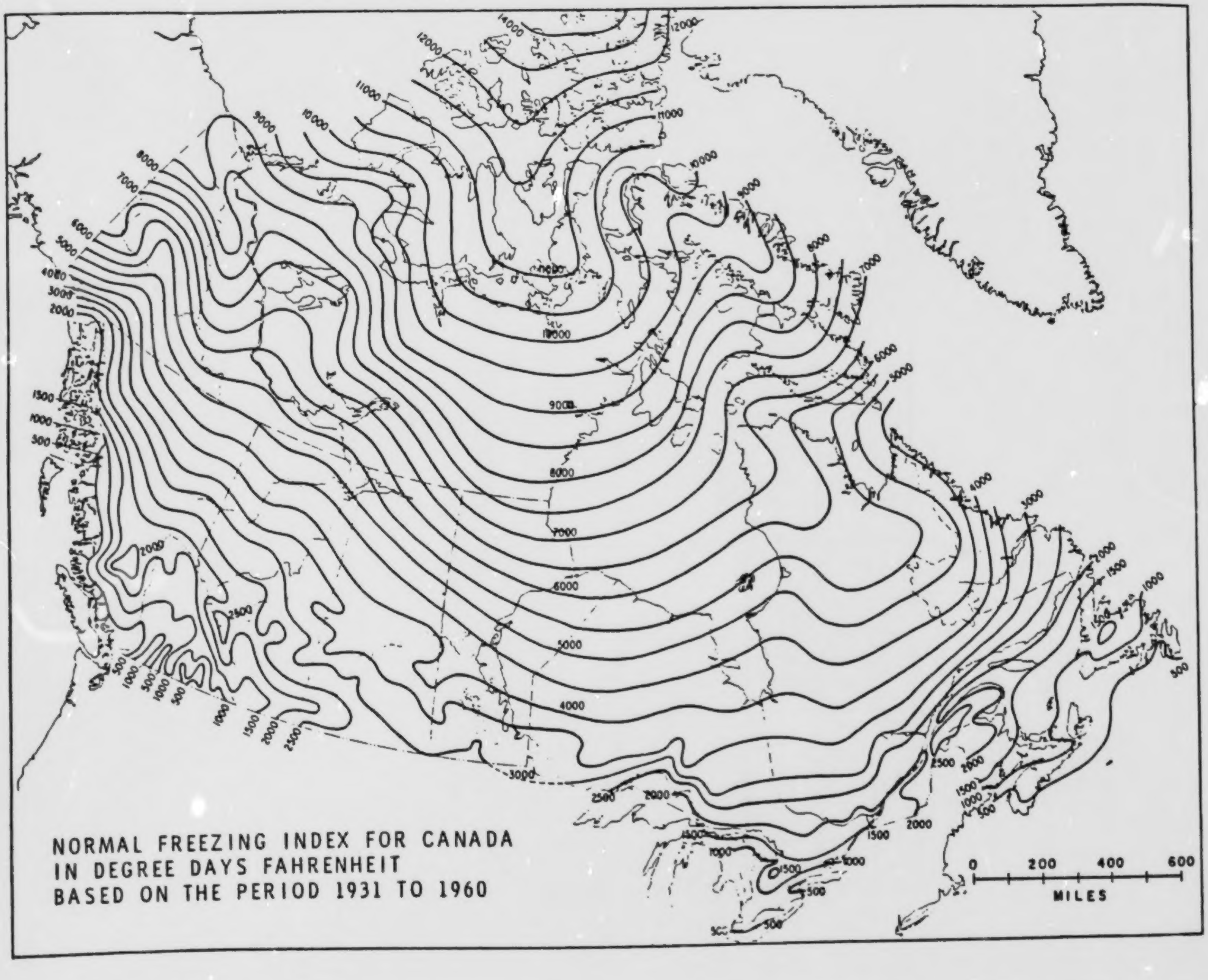
Door locks must not freeze, and doors should open inwards if standing snow is likely to be a problem.

CONCLUSION

Designers, owners and operators are fortunate in the shared knowledge that much of what can go wrong with hydro-electric installations already has.

It is possible that attempting year round operation of a facility would not be cost effective, and some plants cease operation for part of the year.

Cold weather contributes it's own unique problems, but with careful consideration of the nature of those problems, a successful installation can be planned, designed, constructed operated and maintained.


14000
12000
11000
10000
9000
8000
7000
6000
5000
4000
3000
2000
1500
1000
500
2500
0
200
400
600
MILES

NORMAL FREEZING INDEX FOR CANADA
IN DEGREE DAYS FAHRENHEIT
BASED ON THE PERIOD 1931 TO 1960

FIG. 1

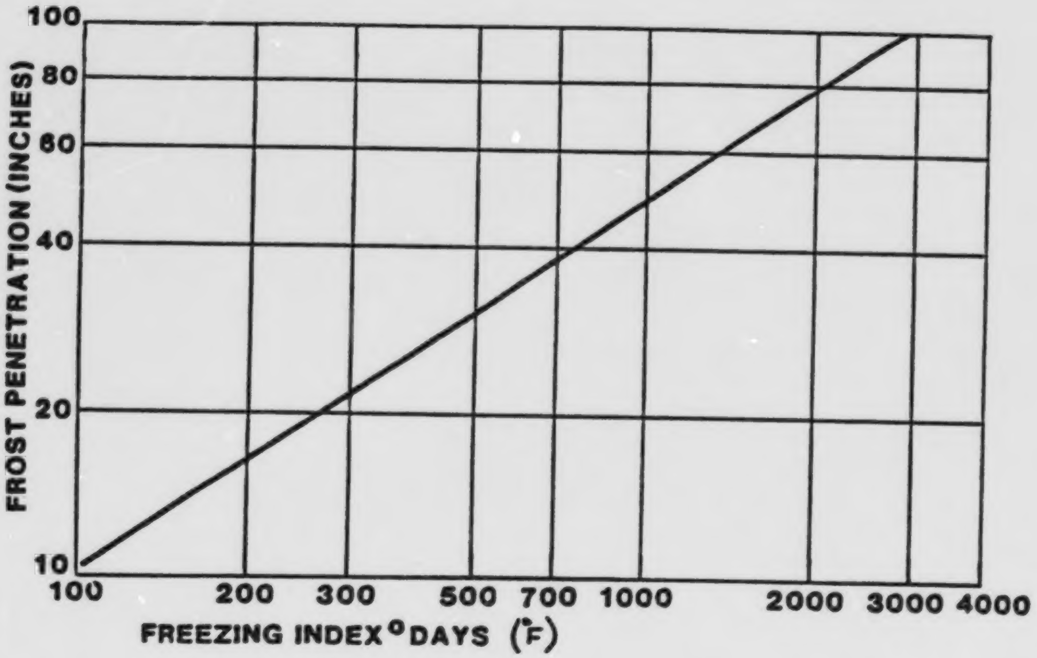

FROST PENETRATION (INCHES)
100
80
60
40
20
10
100
200
300
500
700
1000
2000
3000
4000
FREEZING INDEX ° DAYS (°F)

FIG 2

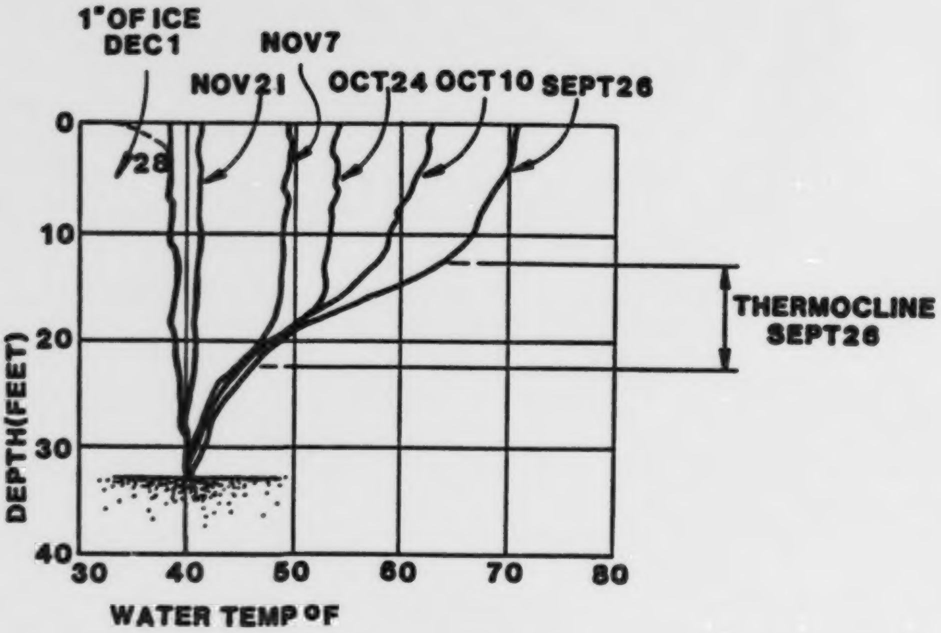

1" OF ICE
DEC 1
NOV 7
NOV 21
OCT 24
OCT 10
SEPT 26
28
THERMOCLINE
SEPT 26
DEPTH (FEET)
0
10
20
30
40
30
40
50
60
70
80
WATER TEMP °F

FIG 3

SESSION 3:

PROJECT FINANCE, NORTH AMERICA

Chairperson: A. Shalaby
Ontario Hydro

Alternative Financing Techniques for Small Hydro Projects

By
J.C. Shepherd

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ALTERNATIVE FINANCING TECHNIQUES FOR SMALL HYDRO PROJECTS

BY: J.C. SHEPHERD

This paper is about the psychology of investors.

People with money - investors - need or want certain things in return for putting their money in someone else's hands. The sensible developer or entrepreneur seeking investment should, before anything else, be analyzing the types of things that investors want, and the ways in which he can give the investors what they want.

This paper is divided into two parts. In the first part, we will look at the types of needs and desires that investors have, since identifying the problems is often half the battle. During the course of that discussion, we will look at some of the obvious considerations in dealing with those needs and desires. In the second part of this paper, consideration will be given to some techniques that one might use in a small hydro project to deliver to investors the satisfaction of those needs and desires as efficiently and painlessly as possible.

WHAT DO INVESTORS WANT?

It is classic investing to see the placement of money as a balancing of risks and rewards. That classic analysis tells us what the first two - and most important - needs of investors are: maximization of rate of return on capital, and a minimization of risk. The bulk of this paper will concern itself with variations on those two themes.

We should not neglect, however, the many other less tangible needs and desires that investors exhibit. These include corporate or personal recognition, the ability to be involved in projects with people that they admire or wish to be seen to deal with, and, perhaps most important, any possible collateral benefits or synergies that they will achieve by making an investment.

Rate of Return

Rate of return is influenced by two things: the amount of capital invested, and the period of time over which the capital and its yield will be paid back out of revenues. In addition, rate of return is obviously affected by risk, since the balancing that is going on is between risk and reward, and it can also be affected by currency of repayment.

When the developer analyzes the needs of an investor, he should be emphasizing in his mind the pressure points that the investor's needs will touch in his planning and operations. A case in point is the impact that variations in the amount of capital required will have on the rate of return an investor can be offered. Assuming that operations - revenue and expenditures - are a constant, increases in the capital cost of the project will reduce the rate of return to the investor, and conversely reductions in the amounts required from the investor will, given the same payments to him, increase his yield.

The ways to control the amount of capital required from the investor can be broadly drawn into two groups - control over the capital cost of the project itself, and finding other sources of capital in addition to that of the investor.

On the issue of capital cost, there are four major components that have to be dealt with: equipment and civil costs; land and water rights; soft costs, including interest during construction; and brokerage costs. All of these amounts can be subject to wide variations. For example, equipment or civil work varies hundreds of percent between the unknown engineer/turbine company and the big multinational engineering firms. There are numerous examples in this province of projects that were built, start to finish, for under Cdn. $800 per kilowatt of installed capacity, yet it would be very surprising if one of the major multinational engineering firms, using name brand equipment, could build something in the 500 kilowatt to one megawatt range for under Cdn. $2,500 per installed kilowatt.

Another example is interest during construction. When government or investor approvals take a very long time, or the work itself takes too long, there is a period during which there is no revenue but the investor's money is in and accruing its yield. To put that in hard terms, the cost of the financing during the construction for a $5,000,000 project taking six months to complete is around $250,000, whereas if that project takes three years to complete (due to environmental assessment, zoning changes, etc.) the cost of financing during the development period may well approach $1,000,000. In a typical situation, that could result in the investors having their yield reduced from 20% to 15%.

The other aspect of how much capital is needed is what other sources are available. In this regard, it is obviously important to the investor and to the developer that the other sources be cheaper sources of financing, or at least less demanding from a cash flow point of view. At the one end of the scale, this means government grants and forgivable loans, or in some cases trade financing from engineers, turbine manufacturers, etc. At the other end of the scale, this may mean, as far as a bank or other institution is concerned, equity, since equity investors rank behind the bank and don't get any money out until the bank has their share.

The other main aspect of rate of return is the payback period. That is in turn dependent on two elements: the revenues of the project, and the expenses of the project. While this may seem simplistic, it is often easy to lose sight of this critical element in the midst of creating yet another spreadsheet for a potential investor.

On the revenue side, the most important pressure point is the most obvious - how much power is being produced. One should not ignore, though, of the importance of prices, and therefore in many cases government policy, on the revenues. Sometimes it is possible to increase your revenues through intelligent negotiation, or through lobbying the government, but in any case it is important that increasing the price be maintained as an important goal.

The expenses of a hydro project, from the investors point of view, boil down to two general areas: operations and maintenance, and taxes and water rates. The investor will be concerned that both of those are under control so that the net profit in any period is maximized for payment to the investor.

Rate of return is also heavily influenced by the currency in which the yield is being paid, and/or the principal is being repaid. It is a fact of life that one can borrow in currencies such as the Swiss franc or the Japanese yen at much lower yields than, for example, the U.S. dollar. If effect, this is simply a matter of the investee taking the risk of currency fluctuation instead of the investor. Small hydro developers are too often afraid of taking a currency risk in order to get an appropriate financing package, and therefore lose opportunities that are otherwise very suitable for them.

Minimizing Risks

Investors see risks everywhere. The whole process of investing is to identify a million risks, then cover off each one of them so that the overall risk of an investment is kept to an absolute and measurable minimum. This is why investors such as banks and venture capitalists, who are very efficient as risk minimization, are so difficult and aggravating to deal with. The bottom line is that they are very good at minimizing risks, but that they do so at the expense of doing considerable violence to the developer's plans.

It is worth emphasizing one thing that is perhaps more important about investment than anything else. Investors do not like uncertainty. It really doesn't matter whether an investment is a high risk equity investment, or conventional bank financing. The nature of the investment process is to make every variable certain. There may still be risks, but those risks must be measured and factored into the risk/reward equation before most investors will put up their money. It is this aversion to uncertainty that more than anything else controls how investors act on a day to day basis.

In a small hydro project, the risks fall into five general categories: financial, operational, construction, marketing, and management risks.

Within the category of financial risks, an investor will be very sensitive to the possibility that the project will have negative cash flow, and what can happen in that situation. Banks, for example, will look at what happens when there are bad water flows, so that cash flow is reduced for a temporary period of time. The banker will want to know that during the period of those bad flows the project is still viable. Similarly, the investor will look at the possibility that payments of revenue to the project will be interrupted, and try to determine whether an interruption of payment, if it is possible, could cause serious damage to the company.

Some small hydro companies need expansion in order to be truly profitable, and investors looking at such a company will be concerned with whether additional investment will be available in the marketplace, and what would happen to the company if that investment were not available. For example, are administrative costs too high for the current level of operation, and require the economies of scale of additional projects in order to bear them?

Virtually always, an investor will want to nail down any other investment that is coming in either prior to or at the same time as his. The investor will look at the risk that government grants are not available, or that promised government grants will actually materialize. Similarly, investors such as banks will often insist on equity coming in at the same time, and conversely equity investors will be concerned with whether conventional financing is in place and the cheque will actually end up being on the table.

Many jurisdictions have tax incentives associated with small hydro and other environmentally benign energy technologies. Canada has such a regime, although there is currently a proposal to restrict its availability to a relatively small group of companies, which proposal is being fought hard by the alternate energy community. From an investor's point of view, the availability of tax incentives, if they are significant economically, will be perceived as a serious risk, and one that the investor will want to be very sure of before he proceeds with his investment. This is often problematic, since tax incentives are by their nature fraught with uncertainties.

The second category is operational risks. These can themselves be divided into three categories: water flows; reliability of the facility; and relationship with the electrical system.

In the case of the water flows, generally the overall risk that the water flows will suddenly change from historical norms is very low. The main area in which there could be a problem is government or private interference with the water flows upstream of the station. Investors will normally want assurances that this is impossible or for some reason highly unlikely. Aside from interference by man in the water flows, the concern is the unpredictability of the variations in the water flow within the ongoing average, and that is in turn a cash flow rather than an operational question. As long as the project can survive the drop in cash flow, investors will normally not be concerned about short term drops in production.

With respect to the equipment and the civil work, the key is simply reliability. The investor would almost always prefer new, brand name machines, and a dam and other civil work built by a contractor with impeccable credentials. As indicated above, these things cost more, and therefore the investor's yield goes down. One of the most interesting aspects of dealing with investors in small hydro projects is watching them balance their greed against their fear in considering issue of brand name versus low price.

The relationship of the project to the system itself is not just a question of whether the generating station will do damage to the system or to other people on the system. That is indeed a fear that investors will be concerned with, but it is one that can be either insured against, or almost totally taken away by technological solutions. The bigger problem is the extent to which the utility or other entity that controls the grid is "jumpy" about private generators, and has the right, by contract or otherwise, to stop receiving power if it gets nervous. That is, it is not just actual damage to the system that can represent a serious operational risk, but perceived imminence of damage by a utility that then refuses to buy power.

The most obvious construction risk is the completion of the project itself. Many investors will simply decline to put up their money until the construction is completed. They will be concerned either with the possibility that various government approvals, etc. will not be received as anticipated, or that once all of the signals are go, the contractors will not be able to produce on time and on budget. Even investors who are willing to put up money after all of the approvals are granted but before the building is completed will normally place very tough restrictions on the selection of the contractors and the terms of the contracts.

Also of some importance during construction is the engineering and the quality of the project, but, as indicated above, this is really more of an operational risk than a construction risk. It is not primarily a question of whether the project gets built, but rather of how reliable and profitable it will be once it is built.

Of more relevance in the context of construction risks is the availability, cost and timing of interconnection with any local or broader grid, or hookup to a user if it is a direct project. In this context, it will be important to ensure that interconnection is available as of right, whether by contract or otherwise, and to nail down the extent to which government policy or the policy of the respective utility is sufficiently clear on that right.

The cost associated with the interconnect, since it is usually paid by the developer in most jurisdictions, is often unknown until the interconnect actually occurs. This uncertainty, like any other uncertainty, creates a serious problem in the financing context. There are numerous examples of investors who, on all other counts, were prepared to invest, but who insisted that the interconnection to the grid be completed or a fixed price be determined for it before their money could flow.

Related to this is a question of timing. Utilities in many jurisdictions have thwarted the plans of private developers by delaying interconnection, sometimes as long as years. As indicated earlier, any delay from the start of a project to the time the project can start generating revenue represents a serious erosion of the yield available to an investor.

Where a project is to be grid connected, the marketing risks are relatively small. Obviously the availability and quality of the contract is important, as well as (in some jurisdictions) the payment record of the utility. Once those are dealt with, marketing ceases to be a problem.

It is much more of a problem with a private user, or with a small local grid such as a remote community. In either case, there are two issues of substance. First, the investor will want to be guaranteed that the private user or the community will guarantee to purchase all of the power, whether they need it or not. If there is no such guarantee, then the risks associated with the economics of the project become magnified substantially. Second, the investor has to be concerned with the ability and willingness of the purchaser of the power to pay for it. A bank, for example, will not be happy to rely on the payment covenant of a single user who is in financial difficulty. Since it is often difficult for the developer to turn around and sell the power to someone else after the connection has occurred, the bank has to be satisfied that the revenue stream will not be interrupted by the financial disability or tardiness of the purchaser.

Finally, investors are always concerned with the two major risks of poor management: ability and commitment. In the first category, management must be able to demonstrate technical knowledge, administrative talents, and an ability to deal with governments and utilities, or with other purchasers, depending on the nature of the project. Investors will also be concerned with the extent to which management is committed to the project, and is honest enough and steadfast enough to maintain that commitment. Investors will generally try to safeguard assets and place external controls on decisions and cash, in order to ensure that any erosion of management's commitment does not cost the investor in the pocketbook.

Other Investor Motivations

Developers often fail to look at some of the other things that drive investors to make one investment as opposed to another. There are many intangibles that go into the investment decision, but three stand out as being of considerable importance on a regular basis.

First, many investors have a collateral benefit available to them from making a particular investment. The investor might be a supplier, or a customer, or may have a related product or process that can benefit from the synergy with the investee company.

The second area in which investors are often motivated is recognition. Where a project might not be saleable on its economics, it can sometimes be saleable on social benefits, or on the extent to which the investment would be good PR for the investor. A particular example of this is one in which an investor can put money into a project in a geographical location important to the investor, such as a small town in which the investor's head office is located.

Finally, the third area in which investors are often influenced is their ability to "get into bed" with people they might otherwise not be dealing with. The most striking example of this is the last few years in Canada was the film industry, which attracted large amounts of investment in part because of tax incentives, but also because investors wanted to be able to be seen and to associate socially with the people in the film industry, who they saw as being "beautiful people". This concept can be imported into the small hydro area if your project has involved in it people whose names have recognition value, and with whom other investors will want to be involved.

There are, of course, hundreds of other ways in which investors are motivated, but it is not possible within a paper of this size to go into them.

HOW DO DEVELOPERS DELIVER THOSE THINGS?

This part of the paper will attempt to list, in point form, a few of the ways in which the developer can use creativity and imagination to deliver on the investor's needs. This is not intended to be exhaustive, but rather a think piece of ideas - some conventional and some unusual - to help the developer figure out ideas that will work for his particular project.

Rate of Return

There are many ways in which the capital that you need from a particular investor can be reduced. Here are some specific examples:

1. **Government Grants.** In many projects, government grants are essential for economic viability. Even when they are not, the developer should be looking at whether there are grants available. Regional development incentives, export financing incentives, etc., are the most obvious to consider. One should not ignore, though, local business development funding, nor grants that might be given simply because of good politics rather than industrial development. One area that many developers often

ignore is research grants. Many small hydro projects require (or could use) technological development in order to work efficiently. Governments love to pay for that sort of thing, and should be invited to do so.

2. Low Interest and/or Forgivable Loans. Governments appear to have trended away from this in recent years, but it is still a common financing technique where the government of one country is financing work to be done in another country, and wants to make sure that the economic or political benefits sought to be achieved in fact materialize. Many entrepreneurs shun low interest loans because they still show a debt to be repaid. Those people would be well advised to remember that the value of a $1,000,000 ten year interest free loan could be as high as $600,000. Getting the interest free loan might be easier than getting a government grant for that amount.

3. Trade Financing. One often wonders why developers and entrepreneurs are not more aggressive with their suppliers and their customers on the financing side. Many suppliers, particularly suppliers of large machinery or major civil work, would be prepared to give very favourable terms to a good customer on a project of substance. One must remember that the sale itself, and the profit generated by it, can be very important to the supplier, even if payment is deferred. This is especially true with a supplier who is sensitive to changes in their income statement. Trade financing can be temporary or permanent. There should be relatively few situations in which it is not possible to do a project with a substantial amount of the financing during construction coming from the supplier's side. Permanent financing from suppliers is somewhat more problematic, especially in an industry where many of the suppliers are either financially insecure or stubborn.

4. Customer Financing. Whether the purchaser of the power is a utility, or a local community, or a private user, they are a potential financier with a natural interest in having the project work, and therefore should be one of the first sources of capital approached. An important variation to this occurs where power is primarily being supplied to a small town. In such a situation, it is often possible to get the middle and upper class residents of the town, to take a substantial equity position in the project, simply by asking them publicly to do so. The

investment by individuals in their own community it one of the easiest investments to close if it is approached in the right way.

5. **Takeout Financing.** This really comes under both variations in the amount of the capital, and minimization of risks. One of the ways of getting investors to put up their money is to show that their money will be repaid to them as soon as certain conditions are met. In effect, this amounts to very precisely identifying the risks that those investors are taking, and guaranteeing to them that they will have their money back as soon as those risks disappear. A common structure is to have equity investors put up the money for the first year or two, until operations reach and maintain a certain level. Then, there is either a sale of the project outright to a third party, or a bank financing. Whichever method is to take place, getting a firm (binding) commitment for the takeout, right at the beginning, creates a level of safety for the equity investor. They then no longer are dependent on operations for return of their capital or (some or all of) their yield. They can determine with precision exactly what the project has to prove, at which time they simply receive a cheque for everything that is due to them.

6. **Borrowing Creditworthiness.** One of the most effective ways of reducing the amount of capital required from an investor is to arrange with a bank or other financial institution to provide the investor with the money, so that the investor's cash out-of-pocket is only a small portion of the amount at risk. In this circumstance, the investor is lending his creditworthiness, not his money. If this seems like a shell game, it is decidedly not that. While the bank charges 12% or 13% for the money, the investor is able to improve his, say, 20% rate of return on 100% of the money to 35% on a quarter of the money (his cash portion). Investors can and do set this up themselves, but having it pre-packaged will often ease the way for a certain class of investors, and allow the developer to present to potential investors a more attractive rate of return from the asset.

Controlling the capital cost of a project is something that is not primarily an investment question, but a management question. Any good developer will try to keep the cost of a project down, and yet will still be striving for reliability and quality work. There are many ideas for how to control the capital cost of a project, but here are four that financiers find particularly attractive:

7. Local Contractors. Use local contractors on the basis that, without properly supervised local work, it will be difficult to get co-operation not only from workers but also from suppliers and customers. This is in some respects an indirect way of using cheaper contractors as well, but can be very successful. It should be noted that this is not a tactic that is restricted to the third world. It is very common in Canada that the use of local contractors will have a salutory effect on the speed, cost and quality of construction.

8. Land/Water Costs. As hydro sites become more and more expensive, land and water costs are going to become a more critical factor in the economics projects. To minimize this cost, it is in some cases possible to get a lease of land or water rights for a period sufficient to pay out the investor's investment, but without the heavy capital outlay. From the point of view of the developer, the lease should have an option to purchase attached to it, but it can be much more expensive at the later date, once the cost of the investor's money has been amortized and paid out. In effect, the owner of the land becomes a secondary financier through the leasing arrangement.

9. Shorten approval process. The length of time for the approval process is a pressure point on the capital cost of the project. The smart developer has as much high powered support - including politicians, community leaders, etc. - as he can to shorten the approval process and get his project onstream as fast as possible. Some developers see the approval process as being inevitable, and see patience as a virtue. It certainly is not.

10. Syndicate through Accountants. Brokerage and other costs can end up being anywhere from 8% to 20% of the cost of the project. With an investment that is generally as low risk as a small hydro project, some developers are starting to use syndications through accounting firms as a much cheaper and sometimes much faster way of raising money. Several accounting firms, including the large ones here in Canada, will syndicate the financing of interesting projects to their clients, charging their accounting fee plus a premium ranging up to, in rare cases, 5% of the amount

financed. Where accounting firms provide the financing through an internal syndication, it is almost always the case that the "brokerage" cost is much less than it would have been had a brokerage house or other financial intermediary been used. As an aside, some of the Canadian banks, and many of the foreign banks, also have the ability to syndicate to customers, and often their fees are much lower than stockbrokers.

Again, revenue and expenses are obviously management issues that show up in a financing package as nothing more than good management. Given that caveat, there are some ways of dealing with the reliability of revenue that will appeal to financiers:

11. **Rate Selection.** Developers in Ontario will be familiar with the two tier rate structure for small hydro projects offered by Ontario Hydro. Most developers will look at the escalating scale, based on consumer prices or other factors, and realize that in the long term it is a better deal than the flat rate currently offered. Most financiers will not see it that way. They will see uncertainty as to the price of power as an additional risk, which can be avoided by a ten year flat rate contract. Then all the financier needs to do is make sure he is repaid within that time frame.

12. **Wheeling.** Where the local utility rates, or the rates of private users or communities in the area, are not sufficient to get a good rate of return, it may be possible to wheel the power to another jurisdiction that will pay more for it. A project in Nova Scotia is presently trying to negotiate such an arrangement, and it looks like they will be able to achieve that result, so that a project that was marginal becomes very profitable. In that case, they are not doing it for financing, but the same consideration applies. It might be noted that, with the free trade agreement, the opportunities for cross-border wheeling are exciting. While Canadian utilities are very resistant to this idea, the pressure in a free trade environment may be too much for them to continue to fight it.

13. **Production Guarantees.** Where a second tier engineering company, for example, is to do the engineering, and as a result the investor is a little less certain of the quality or reliability of the work, it may be possible to get the engineering company to provide a guarantee of the amount of power

that will be produced given assumed flow rates and maintenance schedules. This sometimes can make it possible for the cost of the project to come in lower using the less expensive turbines and civil work, while minimizing the investor's concern over the lack of brand names.

14. **Earnouts.** A variation on the last point occurred recently in a Canadian project. The company building the project for the developer had an overall contract price comparable to that of a large engineering firm. However, about 40% of the price was contingent on performance of the station over the first five years of operation. As performance reached a certain co-efficient based on actual flows, components of the contingent part of the price became payable. It should be noted that there are a number of tax considerations in Canada for setting up this structure properly, and often a carried interest or royalty to the engineering company is the most efficient way of doing this for tax purposes.

15. **Upstream Controls.** The sophisticated small hydro developer will be concerned about who controls the water flow upstream of his facility. Some developers are now acquiring upstream dams, even if not developable, just so they can use those dams to control flow to their facility. In the best of all possible worlds, the developer does not look solely at his site, but at the whole river system, and acquires and develops as many sites on the river system as possible. If the developer can get all of the developable sites on a small river, he can improve the efficiency of each generating station that he owns, and get substantial improvements in revenues. As well as being good management, this is also good investor psychology. Where management has this sort of control over the flow of water, the investor will see this as much more important than it really is, and will be heavily influenced to invest.

The currency risk and its impact on the rate of return the investor will expect can be handled in a couple of ways:

16. **Self Insure.** The developer can simply borrow in foreign currency, and promise to repay in that currency. In a small hydro project, this may not be as bad as it sounds. Normally the investor will require that financial projections be done on a very conservative basis, and the developer knows full well that actual operations are likely to be 10% or 20%

better than the projections he has been forced to prepare. That, coupled with the lower yield that has to be paid on loans in foreign currencies, can provide enough of a cushion for the developer to take the risk of currency fluctuations himself.

17. **Third Party Investment.** The developer can also buy the currency forward, either from an institution or privately. The latter is an interesting and little used concept. Some investors are happy to put up their creditworthiness to guarantee the currency fluctuation, even though they might not want to invest in a small hydro project. From the point of view of the currency investor, he can cost out his currency risk very precisely, and charge for it in the ordinary course. In addition, he can probably demand and get some form of equity or option that allows him to buy into the small hydro facility for virtually nothing. This type of sweetener makes it a very attractive investment for a currency hedger.

Minimizing Risks

There are certain general things that can be done to reduce risks on a broad front. Some of them are:

18. **Guarantors.** It is sometimes possible to have individuals involved in a project personally guarantee some or all of the financing. While this may seem obvious, it is often not thought of in small hydro situations, and yet the involvement of well-heeled individuals and companies is fairly normal. In this context, sometimes suppliers and customers can be the third party guarantors, either directly as guarantors of debt, or indirectly through guaranteeing sufficient operational aspects that the risks are much reduced.

19. **Government Shifting.** Governments are more and more interested in encouraging small hydro development. One of the key aspects of government thinking in this day and age is that they are very averse to spending money, but they still want to achieve the economic and political gains that they would have achieved had they had larger budgets. They can sometimes do this by taking risks in a project without spending money on them. While it is unlikely that a developer will be able to get a government to provide an overall guarantee for a project, it would not be at all surprising if in the appropriate circumstances governments would guarantee or insure certain aspects of the project, such as payment by the purchaser,

level of purchase rates, taxes, water rates, etc. In the latter two examples, one could consider entering into an agreement with the taxing authorities to fix taxes or water rates for a long period, rather than being subjected to the winds of local politics as they change from time to time.

20. Options to Purchase. Financiers will generally have rights to enforce their security if things go wrong, but this may not be sufficient for them if their nervousness is of the more intangible kind, or if the upside of a project causes their greed to get working. In neither of these situations, a financier will be attracted by the possibility that, whether conditionally or simply at their option, they can purchase the project at some time during the period when they are an investor. An option to purchase if things are going poorly is a simple and efficient way for a financier to get control over the project at an inexpensive cost. When things are going well, an option to purchase gives the financier some of the upside, and this translates, in the financier's eyes into a potentially higher rate of return on a project.

The financial risks of small hydro projects are minimized primarily by financial projections which take a very conservative approach. Investors will insist on this, and if developers paint too rosy a picture, the investors will simply redo the numbers to their own satisfaction. Some of the tricks for reducing financial risks are:

21. Reserves. A number of financiers of small hydro facilities are asking for projections that include reserves for flow variations and for equipment breakdowns. Typically, a 2 1/2% to 5% reserve is more than adequate for most investors. Such reserves can be financial reserves, which show up on the projections but do not represent actual cash. Or, they can be of the sinking fund variety, in which there is an actual cash reserve fund set aside out of each month's revenues, to look after periods in which cash flow is reduced.

22. Cross-border Sales. When a purchaser of power is on the other side of a border, the risks of payment interruption are dramatically increased. It may be possible to have this risk insured through export financing mechanisms, in the same way as one would insure that one got paid for goods sold across a border. This is a new concept to most export financing organizations, and so there is an education

curve involved, but it may be worth it in order to reduce the risk for both management and investor.

23. **Administrative Costs.** Where projects are small, or are the first in a series of projects, sometimes the overhead and administrative expenses are too heavy for the initial projects. This can be solved by having the developers look after their own administrative expenses (failing which they simply don't get paid), and shift them to the projects only as a pre-set percentage of revenues. Typically that would be about 8%.

24. **Escrowed Grants.** Governments are notorious for the unfettered discretion with which they decide whether to distribute grant money, even when it has been previously committed. Some people who deal with governments are now asking the governments to place their grant money in an escrow, to be disbursed as the grantee performs under the original granting conditions. This is something the governments will resist to a great extent, but, where an investor insists (or can be persuaded to insist) that the government grant be disbursed and escrowed, this can reduce the possibility that a later discretion will cancel it.

25. **Letters of Credit.** Usually where one investment is dependent on another investment, the second investment has to be the first in, or they have to be simultaneous. Where that is not practical, the use of letters of credit to ensure that the other investment will be in when promised will make many financiers very happy. While this is an added cost of as much as 1% of the second investment, it is worth it for the certainty that it gives to the first investor.

26. **Rulings.** In the area of tax incentives, the rules are sufficiently complicated that many investors will not believe that they are available. They most efficient way of dealing with this, in many jurisdictions, is to get a binding ruling from the tax authorities as to the interpretation of the taxing provisions.

This is really not a paper about control of operational or construction risks, which are things that as a developer you should be dealing with in any case. In general, government guarantees and insurance, the involvement of a third party guarantor, or the use of a turnkey contract, can help minimize these risks. There are a couple of additional specific examples that one could use:

27. Fixed Payment Power Contract. A technique that has been talked about but apparently not yet used in the small hydro context (it is common on the conservation side), is a contract with a user for fixed monthly payments for power, however much is generated. In effect, the risk of variations in production is shifted to the user, and in return the user gets the certainty of contract price and some sort of break on the overall cost of the power. The certainty that this gives to the financier may be sufficient to offset the price benefit achieved by the purchaser of the power.

28. Arbitration. The risk that a utility or other user will disconnect out of fear that the generator will somehow harm the system can be dealt with through tight arbitration provisions, which couple the decision of an independent third party as to whether the utility should disconnect, with the requirement that the utility buy the power that they didn't take if the arbitrator rules against them. Large utilities resist this sort of provision, but increases in government pressure, at least in Canada, may result in this being more viable in the near term.

29. Letters. It is easy to underestimate the value of a letter from the utility or from the government with respect to their policies and their unwillingness to act in an unreasonable manner. Surprisingly, Ontario Hydro has recently shown their willingness to write letters to financiers describing how they will approach discretions given to them in their contracts. Some ministries of energy, including ministers themselves, will also write comfort letters to private financiers where the risks are risks that the financiers see as important, but the governments see as negligible.

28. Meetings with Key Officials. Again, this is often underestimated. Developers are, in fact, afraid of putting their financiers in the same room as utility officials or bureaucrats. Practical experience tells us, though, that, done the right way, these meetings can go a long way towards satisfying investors that the operational and even construction risks associated with small hydro projects (which risks can loom large to the financier) are in fact of very little importance. This is an especially valuable tool when dealing with banks and other institutional lenders. Unlike small hydro developers themselves,

institutions tend to believe what their governments tell them.

Marketing risks are usually contract issues when it comes to utilities, and financing issues when private purchasers or communities are the people who are buying the power. These are some of the easiest risks to deal with:

29. **Contract Terms.** A tightly worded contract with the utility is almost financible by itself, although getting a bankable contract from a utility can be very difficult. It is worth the additional effort to get the contract terms that one wants, and to get the contract in place as early as possible.

30. **Letters of Intent.** With many purchasers, especially utilities, it is not possible to get a contract in place when the money is needed. One way of dealing with this is to get a letter of intent with the utility, and annex the contract that must be signed at the appropriate time. This involves negotiating the contract terms before the project is in place, something most utilities and other purchasers will do only under pressure, but it is worth it for the certainty that it gives to the investor. The execution of the contract becomes a mere clerical matter when the conditions in the letter of intent are satisfied. Usually those conditions would be various government approvals for the project, and some or all of the construction.

31. **Side Letters.** Again, as noted above, utilities are especially noted for their unwillingness to put new provisions in their contracts, even if they are things they would obviously agree to. It is a time tested technique in commercial transactions to use standard form contracts and, in effect, vary them through comfort letters from contracting parties. For example, a contract that provides that the price is only guaranteed for five years can be signed as is, as long as the utility at the same time writes a letter advising that the rate after five years will not be less than some formula that they can stipulate.

32. **Letters of Credit.** Where a private purchaser or a small community is buying the power, the safest way of ensuring that they will pay for it is a letter of credit. Any other way in which a financially secure third party - whether a bank or otherwise - will take the risk the payments will be made will go a long way towards satisfying investors.

Often there isn't much you can do about the management of your project. Small hydro projects are mainly done by companies that lack management, and it doesn't much help to tell them to get the right people in place to make the investors happy. Given that general comment, there are still some things that can be done:

33. **Board of Directors.** Small companies often fail to realize the value of a good board of directors, especially one that has people with recognizable names and reputations that precede them. Such people can be available at fairly low cost, and have the added advantage that their participation at the board of directors level can be useful in helping the developers to properly manage their projects. Indeed, this is the reason why investors like to see them involved. If those people are also given small amounts of equity, or options on equity, this will enhance their interest and the comfort level of the investors.

34. **Joint Ventures.** As the small hydro industry in any given jurisdiction develops, the small companies grow, and a few strong players emerge. Those strong players are, in other industries, often willing to lend assistance to projects that are not theirs, for a fee or some equity participation. There is a tradeoff that goes on here. Giving away some of your project to a larger company is balanced off against the more favourable investment terms that one can get from the financiers.

35. **Investor Involvement.** Most investors will want to have their finger in the operations, and most developers will this. Usually the investors have no idea how to run a small hydro facility in any case, and so allowing them to be involved in any active way would be unwise. It is still possible to allow them a seat on your board, and some financial controls, while maintaining independence on the operational side.

36. **Franchising.** This technique has not yet been used in small hydro. In many other industries, franchising is used in a combination of a financing tool and a method of minimizing business risks. In the small hydro context, it operates as a variation on the joint venture idea above. The more established companies in any local area can allow private developers to do their own projects on their own sites, as franchisees for the larger company. The developers/site owners maintain some or all of their independence, but have

the larger organization's resources available to them, in return for a fee. Investors are much more likely to put up money for a franchise of a successful package then they are to put up money for an untried small hydro developer. One sees numerous examples of people with sites and good ideas who could benefit from borrowing the name of a more successful company. On the other side of the coin, companies expanding their network of generating stations could do well to consider getting local entrepreneurs to buy franchises for some or all of their new sites, so that the expanding operation doesn't need to find the money for that expansion. At least one Canadian small hydro company is right now considering this method of aggressively expanding its operations.

Other Investor Motivations

There are too many areas in which particular investors have their own predilections to list all of the potential structuring ideas that go along with that, but here are some:

37. **Indian Bands.** In Canada, some Indian groups are now becoming financially secure, through land claims settlements other methods. They represent a rich source of potential investment, particularly for projects that will be situated on reserve lands or will benefit communities with large Indian populations. This is a market where one has to be very sensitive to the non-financial needs and desires of the investors, but also one in which, handled properly, there is great potential for available funding.

38. **Regional Institutions.** In Canada, many trust companies and other financial institutions and large businesses have a regional base. Where a project is suitably located, a financial institution with that regional base will be more strongly inclined to put up money because they will be seen in their home community to be acting in that community's interests.

39. **Unions.** Again, many unions have particular interests in certain geographic areas, or interests in the development of certain technologies. Unions are active investors, and like investments that have social spinoffs and are environmentally benign, etc. Unions will also see the provision of inexpensive power in a locale in which they have any interest to be a way of increasing the industrial potential of

that area, and thus to be something that they should strive for.

40. **Municipalities.** In general, municipalities do not like to spend their money on small hydro projects, because it is often harder for them to go through the bureaucracy of finding the money than it is for the private developer to do so. The idea should not be rejected out of hand, though. Some municipalities do have money, and the others who do not are sometimes able to provide third party investors with comfort (short of guarantees but close enough) that can facilitate those investments. For example, in one situation currently under negotiation a town agrees to buy all of the power from a private developer for a fixed period of time, with the price escalating dramatically halfway through the contract. At the time of the price escalation, the municipality has an option to buy the facility at an attractive profit to the developer. Because the price of power would be going up immediately after, the option is almost certain to be exercised, and this gives the investor a lot of comfort that he will be taken out at that time.

Conclusion

One could go on and on with examples of techniques that can be used to enhance the ability to finance small hydro projects, or to finance them in non-standard ways. The true point, though, is that creative financing involves understanding what investors want, and using the natural advantages of your particular project to give them what they want.

Small Scale Hydro Sites as an Example of Privatization

By
P.J. Bulandr, D.E. Keats

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"SMALL SCALE HYDROPOWER SITES AS AN EXAMPLE OF PRIVATIZATION"

BY: [1]Peter J. Bulandr, and [2]Douglas E. Keats

During the 1970's in the U.S.A., there was growing sentiment to support alternative energy production. As you know, this culminated in the passage of the Public Utilities Regulatory Policies Act (PURPA) requiring the utilities to purchase power from alternative users, subsequently, various tax benefits were mandated as well. Many new firms sprung up to take advantage of the situation and actively sought to get their permits, exemptions or licenses from the Federal Energy Regulatory Commission (FERC). Our firm missed the initial phase of this dash for sites.

Concurrently, a new approach to providing public services gained favor. The concept was privatization. In simple single terms, privatization is the private operation of public services. Our firm also missed the initial phase of this concept. However, hydropower development and privatization brought us into play later on.

Our firm is STS Consultants, Ltd. We are headquartered in Northbrook, Illinois. STS began its consulting engineering practice in 1948. Prior to 1982, all of our assets pertained to the laboratory, office and/or field equipment involving a civil engineering practice. In 1982, we became consultants to the County of Kent, Michigan on a dispute concerning their dam. Several other firms and the State of Michigan felt the dam was failing. Our studies showed that their assessment was erroneous, and only rehabilitation of dam was required. Our barter payment from the County was the ownership of the old hydroplant and the adjoining land. Unbeknownst to us, this single job launched a new area for STS.

Subsequently, STS began to produce energy though our private development and operation. The alternative was for the County to produce power. Our decision to continue to "privatize" after this one project was based on other failures of "would-be" developers in hydropower. The scarce commodity in many of these "would-be" developers had been their lack of engineering expertise. Many sites were available. Many sites had potential. The differential is the distinguishing between a good site and a bad site in technical and economic terms. STS's strengths were in its engineering and construction management capabilities and its economic analysis capabilities.

It was not a hard step for STS to begin to develop sites when we had done engineering and economic reviews. By doing so, we took the easy next step in arranging financing and subsequently, we went a step further into the construction management operations and maintenance of the plant. We feel we provide the services more reliably and effectively than many a public owner could.

Moving into hydropower development has allowed our staff to be developers and operators of quality sites. Our special imprimatur has been the engineering and design to create high quality award-winning projects for their technical aspects. Our successes with the Fallasburg power plant and our 21st century Morrow power plant are specific projects with creativity and innovation.

More into specifics, Chart I shows the dramatic percentage change in the STS balance sheet for the years 1983 to 1987 in becoming a developer of hydroelectric plants. As you can see, the capital intensive nature of hydro has great impact versus the actual revenues derived for our total billing.

Why did STS change its position after thirty-five years in business? Basically, because we did not see it as a change. Our efforts to provide quality, effective services has given us the opportunity to know projects and our limits. Working here was within the corporate limits comfortable to us. Having a guaranteed market was actually a improvement to an hourly rate service business.

Yet, the second side to this issue was the STS ability to finance its projects. For the initial projects, STS used its financial strength to raise the appropriate funds. As STS became more serious and began to do more projects, it became obvious that we had to reassess how this was handled. We restructured the entire corporate configuration. The plan we settled on was to form a separate subsidiary who would be our hydropower developer. That company had the backup of the STS Holdings Group and therefore, had a resource base and expertise to fall back on. However, we could use the subsidiary to go out and get project financing and make arrangements with utilities and private concerns for possible development of sites. The evolution of this decision took approximately five years and was finalized in 1987.

The use of project financing has been of great benefit to us. With the addition in 1987 of financial staff, and the corporate reorganization, we had a golden opportunity to start again from scratch and do it right. We have changed our financing from short term working capital lines to long term project financing in the 10 to 15 year range. Our agreements with the utilities are all long term in scope as our firm is a long term thinking firm. Our relationship with our clients on hydro plant sites are long term as well.

Chart II shows the reorganization of where our holding company and operating companies all fit together in relationship to the hydropower development scheme. You can see the use of several corporations provides flexibility for financing, yet we review financial reporting on a company by company basis.

The final outcome is that as of mid-1988, STS has on line, 8.5 megawatts of power. There are six sites and the annual production is 33 million kilowatt hours per year. We have additional sites we are constructing which will double the outstanding capacity and production. Estimated revenue comes to approximately $2-3 million per year which is approximately 10% of our business. Our long term goal is by the early 1990's to have between 20-25% of our gross revenues in hydro for any one year. We will see how hydropower developments work into the future. Hopefully, our efforts may be of interest to other technical firms wrestling with the issues of diversification and development.

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HYDRO AS PRIVATIZATION

STS

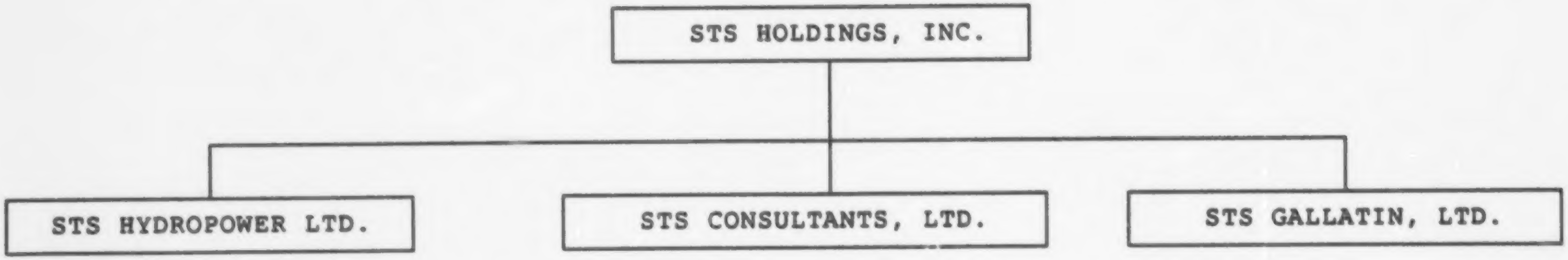
CHART I

	12/83	12/87
HYDRO ASSETS		
Percentage of Total Assets	10%	45%
Percentage of Revenue	2%	7%

HYDRO AS PRIVATIZATION

STS

CHART II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Acceptable Financing Arrangements for Transfer of Interest in Small Hydro Project in the United States

By
P.C. Kissel

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ACCEPTABLE FINANCING ARRANGEMENTS FOR TRANSFERAL OF INTERESTS IN HYDRO PROJECTS IN THE UNITED STATES

Peter C. Kissel[*]

I. Introduction

Over the past several years, the emphasis in small hydropower project development in the United States has shifted from initial authorization and construction to the transferal of project ownership and/or equity interests. This is primarily because, as many small developers have received project authorization, they have realized a need to obtain outside assistance in financing. The need for financing assistance by such developers has conveniently occurred at a time when a number of large companies with solid financial histories have demonstrated an increasing interest in acquiring new projects. In situations involving the introduction of new financing interests into licensed projects, it is essential that any arrangements be compatible with the regulatory scheme established and administered by the Federal Energy Regulatory Commission ("FERC").

This paper will identify the principal statutory and regulatory concerns which are presented by the introduction of new financing interests in projects, and illustrate some of the representative types of arrangements approved by the FERC. While the focus of this paper is presented in the context of licensed projects which seek to include new financing interests or transfer such interests, most of the principles discussed are equally applicable to the structuring of financing arrangements at any stage of project development. In other words, the basic legal and regulatory framework applies with equal force at the initial project planning stage as well as in circumstances involving a transfer of interests.

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II. Overview: Nature and Basis of Federal Energy Regulatory Commission Interest In Financing.

The first question which may logically come to mind is: Why is the FERC, a licensing agency, interested and involved in the financing aspect of proposals? The simple answer to the question is that the FERC must consider the financing structure because Congress has directed it to do so. Essentially, three separate provisions of the Federal Power Act ("FPA") lead to the FERC's authority and responsibility to inquire into financing. The first of these is Section 23(b) of the FPA, 16 U.S.C.§817(b), which provides in broad terms that "it shall be unlawful..." for anyone to operate a project without a license. Second, with respect to licensed projects, Section 10(c) of the FPA, 16 U.S.C. §803(c) states that the licensee "shall maintain the project works..." in an adequate condition of repair and "shall conform to such rules and regulations as the Commission may from time to time prescribe...." Thus, any entity which desires to operate a hydro project must obtain a license, and in accepting a license, the operator agrees to conform to any rules which the FERC establishes.

Third, and most important for the topic of transfers and financing, Section 8 of the FPA, 16 U.S.C. §801, states that "no voluntary transfer of any license, or of the rights thereunder granted, shall be made without the written approval of the Commission..." and further that "any successor or assign of the rights of such license, whether by voluntary transfer, judicial sale, foreclosure sale, or otherwise, shall be subject to the conditions of the license...to the same extent as if such successor of assign were the original licensee...." Section 8 then provides that a mortgage or trustee or judicial sale shall not be deemed a voluntary transfer. Thus, in Section 8, Congress explicitly provided that every voluntary transfer of any rights under a license must receive FERC approval. In so doing, Congress also explicitly recognized that mortgage or trust deeds in judicial sales do not require express written approval of the Commission, but are nevertheless fully subject to all the terms and conditions of the license.

The FERC has promulgated a number of regulatory provisions to implement its authority over transfers and rights held under a license. The cornerstone regulation in this area is Section 4.32(a)(1) of the Commission's Rules, governing the content of applications. That regulation states that any entity "that has or intends to obtain and will maintain any proprietary right necessary to...the project" must be named on the license application. In conjunction with this, the Commission's Standard Article 5, which has been included as a condition in every license ever issued by the FERC, states that the licensee "shall retain possession of all project property..." including "franchises, easements..." and the like.

The Commission has also adopted a number of regulations providing specific guidance to applicants/licensees in carrying out the policies of Section 4.32 and Standard Article 5. Sections 9.1 through 9.3 of the Commission's regulations establish procedures for the transfer of licenses as contemplated by Section 8 of the FPA. The regulations state that an application is required for the transfer of a license, specify the contents of such an application, and set forth the standard for approving transfers, i.e, that such transfer "is in the public interest". The prescribed format for the transfer application is additionally set forth in detail in Section 131.20 of the Commission's regulations.

The necessity for an application for a proposed lease of project property is covered in Section 9.10 of the Commission's regulations. That Section states that any licensee who desires to lease any part of project property for use by others shall file the proposed lease and an application (although no form for such an application is provided) with the Commission. Section 9.10 does not apply directly to financing interests, but rather is applicable to situations where the licensee wants to grant occupancy or possession rights to a third party. This is typically done, for instance, if a park agency of local governmental entity wishes to use part of the project property for public recreational purposes. While Section 9.10 may not be directly applicable to financing, it further demonstrates the pervasive nature of the Commission's interest in any kind of transfer of any rights under a license.

One additional regulatory section worth mentioning is Part 34 of the Commission's regulations, entitled "Application for Authorization For The Issuance Of Securities Or The Assumption Of Liabilities". Section 34.1 in particular states that its provisions apply to any application to "assume an obligation or liability" which is filed by a licensee. This regulatory section applies to a more traditional, straightforward loan from lending institutions to the license holder for project construction and operations, where the lender does not acquire an interest in project rights. A recent example of this type of filing is the application filed on May 12, 1988 by Catalyst Old River Hydroelectric Limited Partnership in Docket No. ES88-37, wherein Catalyst Old River sought Commission approval to obtain a $375,000,000 construction loan from a syndicate of banks. In such a situation involving a more traditional loan, it is not necessary to include the lender as a co-licensee, but Commission approval is nevertheless required.

To summarize, the FERC is charged with certain statutory duties and responsibilities to ensure that licenses are operated in a manner consistent with "the efficient operation of said works in the development and transmission of power...." FPA, §10(c). Any ownership interest in licensed project works is presumed to affect the public interest. Therefore, the FERC not only must approve licenses in the first instance, but also must approve any "voluntary transfer" of project interests or rights. In its first major policymaking case dealing with jointly held project interests, the Commission back in 1981 stated that "an applicant is required to hold or intend to acquire those rights, or it must file as a joint applicant with other parties that will...hold rights necessary for project purposes." City of Fayetteville Public Works Commission, 16 FERC ¶61,209 (1981). In making this statement, the Commission was basically re-emphasizing, for the benefit of applicants, the requirements of the FPA and Section 4.32 of its regulations.

III. The Evolution of Federal Energy Regulatory Commission Policy To Encourage Innovative Financing.

The Commission recognizes that financing is an important factor in the ability of applicants/licensees to operate projects properly. Even in its recent rulemaking proposal on relicensing in Docket No. RM87-33,[1/] the Commission has reiterated this point, stating that it will "inquire into an applicant's plan to finance the project". The Commission explained that it was necessary to do so in order to determine "whether the financing plans are realistic under existing interest rates and market conditions." Thus, it is important to remember, that satisfying the Commission as to the financial feasibility of the project does not end the Commission's inquiry into the financing ability of the applicant.

In its first landmark case involving a transfer of project interests for financing purposes subsequent to the issuance of a license, the Commission approved the transfer as proposed by the original licensee only after determining that the financing proposal was superior to competitive proposals.

[1/] Hydroelectric Relicensing Regulations Under The Federal Power Act, Docket No. RM87-33-000, "Notice of Proposed Rulemaking" (May 24, 1988).

City of Vidalia, Louisiana and Catalyst Old River Hydroelectric Limited Partnership, 31 FERC ¶61,237 (1985). In so doing, the Commission denied a competitor's proposal to take over the license, because the competing applicant's general statement to the effect that it would engage a major Wall Street financing house to arrange financing was not considered sufficient. The Commission stated that the ability to finance is a "key factor" in competitive transfer proceedings, and that the specifics of any arrangements must be examined.

It can be observed that the FERC has two overriding goals to fulfill in considering the allowance of new financing interests in a licensed project. The first goal is to get licensed projects up and operating, and the second is to carry out the Commission's responsibilities under Section 10(c) of the FPA to ensure that projects are operated in an adequate condition of repair. The first goal is most obvious from the straightforward language contained in most of the Commission's orders approving transfers. As its principal justification for approving transfers, the Commission typically states that the transfer is necessary in order to "facilitate financing"2/ or, more typically, "to facilitate financing and construction of the project"3/. The Commission's efforts to encourage innovative financing extends not only to those situations where necessary to complete project construction, but also to projects which have commenced construction and are in need of an injection of new financing to continue operation. As stated in Tuscarora Yarns, Inc., the transfer was approved "to facilitate financing and continued operation of the project". 34 FERC ¶62,154 (1986) (emphasis supplied).

The Commission's second goal, as mentioned above, is to discharge its statutory duty in exercising jurisdictional responsibility over the licensee. This policy of the Commission is not necessarily referenced in each transfer order, but is emphasized in broad terms from time to time in the form of broad-ranging policy statements. Innovative financing arrangements are permissible "provided the licensee maintains sufficient ownership and control of a project to

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2/ See, e.g., Stewart Ranches, Inc., Project No. 7120-007, "Order Approving Transfer of License" (April 29, 1988); Boott Hydropower, Inc., 33 FERC ¶62,440 (1985).

3/ Pujet Sound Power And Light Company and McMaster & Schroeder, 43 FERC ¶62,293 (1988); Halifax County, Virginia, 43 FERC ¶62,029 (1988); Robert W. Shaw, 27 FERC ¶62,027 (1984) Pocantico Development Associates, Inc., 34 FERC ¶62,156 (1986).

enable the Commission, through the licensee, to carry out its regulatory responsibilities with respect to that project." City of New Martinsville, West Virginia, 23 FERC ¶61,268 (1985). In one recent case, the Commission stated that it was approving a total transfer of project rights from one municipality to another municipality in order "to cure an existing default of the bond issue used to finance the construction of the project." City of Vanceburg, Kentucky, 43 FERC ¶62,044 (1988).

From this overview of the Commission's evolution of policy, it is possible to examine the general parameters for financing arrangements outlined by the FERC involving particular situations. Several specific guidelines have emerged.

First, a simple trustee need not be named as a licensee, where the role of the trustee is "very limited" and is not a beneficiary of the trust or the estate. Boott Mills, Inc., 25 FERC ¶61,386 (1983). While this concept may seem rather basic and obvious now, it represented an important step for the Commission in 1983. In the Boott Mills case, the Commission was signaling for the first time its receptiveness to innovative, complex financing arrangements and providing guidance on a particular matter of concern.

Second, the beneficiary of the trust must be named as a co-licensee via formal Section 8 transfer proceedings. This principle was set forth in the same Boott Mills case referenced immediately above, where the Commission approved a partial transfer to include as a co-licensee a credit corporation that would take ownership of some of the project property. The Commission noted that fee title to all new facilities would be transferred to the credit corporation, and agreed with the original licensee that the credit corporation should be included as a co-licensee.

Third, individual partners, limited or general, in a partnership need not be named as licensees. Little Falls Hydroelectric Associates, 28 FERC ¶61,214 (1984). The Little Falls case announcing this policy represented a major step forward in the Commission's evolving policy. It was particularly significant because the Commission's determination reversed a preliminary staff ruling on this issue. Up until the Commission's Little Falls ruling, which was an appeal of staff action, the unofficial consensus opinion was that individual partners were required to be named as co-licensees.

Fourth, a transfer of legal title to a project pursuant to an installment sales agreement does not necessarily require Commission approval, if the title holder simultaneously grants an irrevocable right back to the licensee to construct, operate, and maintain the project. This principle was stated in a further evolution of the Little Falls case. Little Falls Hydroelectric Associates, 29 FERC ¶61,001 (1984). The key to the Commission's acceptance of such an arrangement is that the grant must give the license the right to "perform any and all acts required by Commission orders and regulations, the license, and the FPA."

Fifth, it is particularly helpful to keep in mind that the revenue stream is not a determining factor in deciding who must be named as a co-licensee. On the last day of 1984, the Commission sanctioned a financing arrangement, without the necessity of including equity investors as co-licensees, in El Dorado Irrigation District, 29 FERC ¶61,375 (1984). In that case, private investors financed the Upper Mountain Project, including contributions to equity in return for future tax benefits and a portion of the revenue stream. Project revenues were disbursed in the following order: 1) to fund operation and maintenance; 2) to the investors to pay off debt; 3) to the licensee; and 4) to the equity investors. It was held that the investors need not be included as the licensees. The Commission took this concept a slight step further in the City of New Martinsville case, referenced above. In that case, revenues were paid out as follows: 1) to project O & M; 2) to pay taxes; 3) to pay debt; and 4) to the licensee and the limited partnership equity investors jointly pursuant to a formula "to the extent revenues are available." Thus, in City Of New Martinsville, payout to the licensee occurred at the same point in time as payout to the equity investors. Yet, as in the El Dorado decision, the Commission ruled that the investors need not be named as co-licensees.

Sixth, title to the project property coupled with control over project operation, even for a limited period of time, requires identification of the financing party as a licensee. In a separate case involving El Dorado Irrigation District, the Commission ruled that a proposed financing arrangement was not consistent with the terms of the license as issued. El Dorado Irrigation District, 37 FERC ¶61,219 (1986). In this case, the financing entity was to take ownership and control of the project for a thirteen-year period. The Commission stated that this was not allowed unless the financing entity was included as a co-licensee. In its holding, the Commission emphasized particularly that the original licensee would not hold any "proprietary interest" for the thirteen-year duration.

IV. Mechanisms For Incorporating New Financing Interests

From the above, it can been seen that there are at least five basic methods by which new financing interests may be included in a project.

First, the licensee can undertake a straight loan without the lender acquiring any interest in the project for regulatory purposes. This is considered to be an assumption of liabilities under Part 34 of the Commission's regulations, such as the Catalyst Old River Hydroelectric Limited Partnership case mentioned earlier. The lenders in such a situation need not be included as co-licensees.

Second, the licensee may seek a formal transfer proceeding under Section 8 of the FPA and Section 9.1 of the FERC's regulations. This kind of formal transfer is necessary if the financing party is to acquire any proprietary rights "necessary for project operation" or otherwise to maintain control over management and operation of the project. This approach has the advantage of legal and regulatory certainty. By seeking a formal transfer, the licensee and its financiers are assured that they will not be charged with any potential violations of the FPA or the Commission's regulations.

However, a formal transfer proceeding has certain disadvantages. One of these is the necessary time lag for regulatory approval. Of greater potential consequence, however, a formal transfer proceeding may expose the project sponsors to objections and even competition from other interests. The Commission has indicated that at least in situations where the licensee is a municipality, such transfers must be subjected to competition. City of Vidalia, id.

Third, the necessity for a formal transfer proceeding may be avoided by incorporating the financing entity into the legal structure of the licensee. If the licensee is a corporation, this may be accomplished through a sale of stock to the financing entity in return for the financing assistance. If the licensee is a partnership, the addition of new general or limited partners is allowable under the Little Falls rule. No formal "transfer" occurs as long as the licensed entity remains in existence.

Fourth, a formal transfer proceeding may also be avoided through the transfer of title/leaseback of license rights arrangement approved in the second Little Falls case mentioned above. This type of arrangement was also approved in Long Lake Energy Corporation, 33 FERC ¶61,265 (1985).

Fifth, no transfer is necessary in a situation where the financing parties' interest in the project is limited to a share of the revenue stream. So long as no control over the project or the property is given to the financing entity, a right to share in the revenue stream does not require identification as a co-licensee under the El Dorado rule.

In considering any financing arrangement, even those where no formal transfer is necessary, an additional cautionary note should be added. The FERC has indicated that it expects to be informed of new financing arrangements even where no formal transfer proceeding is required. "We must caution...prospective licensees that we expect full disclosure of...financing plans when they file applications to transfer licenses _or other requests_ involving financing considerations." _Little Falls_, _id_.

In conclusion, there are a number of general guidelines and arrangements under which new financing entities may become involved in a project, as discussed above. Obviously, there are innumerable permutations of the above types of arrangements. In structuring project financing, it is important to be aware of the statutory and regulatory constraints, but it equally important to keep in mind that the FERC encourages innovative financing. As the Commission stated in the _City of New Martinsville_ policy ruling,:

> Recently the Commission has noted an increased interest among licensees and license applicants in employing new methods of financing hydropower projects. Such arrangements are permissible, provided licensees maintain in such arrangements sufficient ownership and control of a project...

City of New Martinsville, 23 FERC ¶61,268. The panoply of allowable arrangements can be expected to expand further, as the FERC acts on new requests in the future.

Powerplant and Dam Insurance for the Small Hydro Owner

By
T.K. Dahlstrand

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POWERPLANT AND DAM INSURANCE
FOR THE SMALL HYDRO OWNER

by

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Abstract

The small hydro owner recognizes the necessity of reliable operation in order to be successful. To help reduce the financial risks and liabilities inherent to the hydropower business, powerplant and dam insurance are desirable. Powerplant insurance on buildings and contents is generally available. However, the owner is probably unable to purchase downstream liability and dam replacement insurance.

The paper will review the insurance industry attitude towards dams and powerplants. An overview of coverage limits available in the past as well as current market conditions will be presented. An important part of this discussion is "how to sell the project" to the insurance company.

For powerplant and equipment, the types of insurance commonly purchased will be discussed. This includes general liability, conventional property damage insurance, boiler and machinery insurance, and business interruption insurance.

Downstream liability insurance and dam replacement insurance are either not available or are unaffordable. Despite these conditions, state and federal regulators as well as many dam owners, believe that these types of insurance are needed by the dam owner community. This paper will present possible solutions to this insurance dilemma through the formation of a Risk Retention Group (RRG) or through an existing insurance company. The discussion will include projected underwriting standards and coverage limits.

Using the information contained in this paper, the small hydro owner will be appraised of available insurance options, how to "sell the project" to an insurance company, and recent efforts to resolve the downstream liability dilemma.

Introduction

The small hydro owner has a significant investment in buildings equipment, and dams. To support the operation, reliable operation of the generating equipment is essential. While periodic maintenance helps prolong equipment service life, catastrophic events can render a powerplant off line for long periods of time. If a major dam problem occurs, the powerplant could be literally offline for years. Most powerplant owners agree that insurance is the protection they require for these types of catastrophic occurrences.

This paper will examine types of insurance available for the powerplant, generating equipment and dams, including typical coverage limits. Prevailing insurance company attitudes will also be presented. Tips to help the hydro owner "sell to project" to the insurance company will also be presented. Using information contained in this paper, the small hydro owner will be appraised of available insurance options in the United States.

Powerplant Insurance

The types of insurance that would be purchased by small hydro owners may be generally described as that associated with the power generating equipment and powerplant property. In the United States, several specialized insurance brokers are offering powerplant coverage, including flood and earthquake. They report that project sizes range from $50,000 to $10,000,000.

For the powerplant, conventional all risk property insurance is normally purchased for the replacement value of the building and contents. Careful attention should be paid to the exclusions in the all risk policy, since it is common to have floods and earthquakes excluded. Floods risks are especially important to hydro operations. However, several specialized insurance companies will offer flood and earthquake coverage.

Generating equipment inside the powerhouse is normally insured by companies specializing in boiler and machinery insurance. This insurance is for damages arising from sudden and accidental failure. In the United States, The Travelers and The Hartford Steam Boiler Inspection and Insurance Co. will provide this coverage. Since there is a major emphasis on loss control, they will perform site inspections and have the option to cancel the policy at any time. Over one-third of the premium costs are for support of engineering staff to perform the inspections. The limits on this coverage should be the replacement value new of the equipment and not book value. The exclusions should also be carefully reviewed since floods may be specified.

Business interruption insurance is intended to provide coverage for lost income and continuing expenses, such as interest on loans, if power cannot be delivered. The policy will carry a deductible and is normally written for a calendar year.

General liability insurance coverage for hydropower projects protects insureds against liability arising out of their premises or out of their operations on or off those premises. Comprehensive general liability covers all sources of liability that are not specifically excluded by the policy. The exclusions should be carefully reviewed. Such exclusions include liability assumed under any contract (such as a power sale contract) and liability concerning the release of pollutants. In cases where the insurer is unfamiliar with the hydro business, hydroelectric operations may be excluded.

Liability coverage is usually for the dam/powerplant site and does not include downstream liability. In Colorado, however, where downstream liability is limited by law to $500,000, this liability coverage is now becoming available to dam and reservoir owners. Normally, it is purchased in the form of an underlying policy of $1 million and an umbrella policy. Five years ago coverage limits to $15 million were available. In 1986, no umbrella coverage was reasonably priced, however, it now can be purchased in $5 million increments up to about $10 million.

Dam Insurance

The dam is a vital and expensive part of most hydroelectric operations. Flood damage to 25 earth embankment dams in Kansas in 1986 had estimated repair costs in the range of $2,012 to $215,278. Although the low end cost may be manageable for most small hydro owners, the high end is probably excessive. Insuring the dam for replacement or major damage repair is virtually impossible in today's insurance market. This situation is probably the result of several factors:

- Dams are complex engineering structures and require significant engineering expertise to evaluate for safety.
- Dams are not well understood by the insurance industry and are perceived as a major risk.

- Dam safety regulation in the U.S. is still in the formative stage.

- The dam insurance market is not particularly large and thus the insurance industry is not interested in product development.

Conventional all risk property coverage would be unsatisfactory for a dam since such perils as flood, wave action, and earth movement damage will be excluded. The dam is a unique risk that requires creative underwriting. Until a time when dam replacement insurance is available, the hydro owner must be responsible for making the dam as safe as possible by having adequate spillway capacity, regular inspections and frequent maintenance.

Dams represent a significant liability exposure to the owner/operator due to impacts on downstream and upstream development. The magnitude of the liability is probably far in excess of insurance limits commonly available or purchased. In fact, the magnitude of liability may change with time as development occurs within the floodway of the dam. The dam owners liability exposure is principally from the failure of the dam, causing flooding in excess of what would have occurred had the dam not failed. This incremental damage can be modeled with available computer technology, considering either flood or nonflood conditions.

Procuring Insurance

Since the insurance a hydropower owner requires is specialized, he must be prepared to answer many specific questions regarding his project. Often a long application and insurer site visit is needed, prior to receiving an insurance quotation. Important decisions need to made by the owner regarding the value of the property and equipment, the tolerable risk, and the value of the reduced risk.

When contacting an insurer, the owner should be prepared to sell the project. Some items an owner should be prepared to show the insurer include:

- The dam and powerplant are maintained with good housekeeping practices

- Document that the power generating equipment has all required protective devices

-Be certain that the project meets or exceeds all safety standards

-Secure the site from all trespassers with signs, fences, spillway markers and safe passage areas

-Have regular inspections of the facilities performed

-Develop written operation and emergency action plans

When procuring insurance, be sure that the insurance agent/broker has experience with hydro plants, and specializes in this type of insurance. Approach the agent at least sixty to ninety days prior to the time coverage will take effect. Finally, evaluate the insurance on the basis of value of the coverage (including coverage limits and deductibles), not simply price.

Cost is an important element and needs to be balanced with the coverage offered. The availability and cost of insurance changes from year to year in response to market conditions. It is difficult to generalize the cost of insurance for hydro plants since ever situation is different. Even for the same plant, rates can vary. For example, 1988 mechanical breakdown insurance quotations for a 2 megawatt plant ranged from $2,500 to $7,800. For the same project property and liability insurance were quoted but excluded flood and earthquake.

Over the past three years, umbrella liability insurance for hydro operations has ranged from about $1.30 per $100 coverage to $5.00 per $100 coverage. Currently, property insurance coverage nearly always exclude floods and can be expected to vary widely. Rates as low $.25 per $100 coverage to as high as $2.50 per $100 coverage have been noted.

How much would flood insurance be expected to cost? To estimate this, a U.S. government program can be evaluated. The National Flood Insurance Program (NFIP) was begun in 1968 enabling property owners to purchase flood insurance which was not available from commercial insurance companies. It was designed as an insurance alternate to federal disaster assistance. Although this program is partially subsidized by the federal government and the coverage limits are low, it indicates an order of magnitude cost for flood insurance. The rates vary with flood risk (location and elevation of the structure relative to the flood area), but can be as low as $.06 per $100 of coverage. For buildings exposed to flood damage rates can be as high as $25 per $100 of coverage. Power plants and dams are a special type of property and would be expected to be at the high end of costs.

Catastrophe Insurance

Despite the many types of insurance that can be purchased for a hydropower project, there are still gaps that represent a significant exposure to the small hydro owner. Specifically, dam replacement insurance and downstream liability coverage are generally not offered in a form that is best for the hydro owner. If available, they will have exclusions that are unsuitable to the hydro owner, such as flood and wave action.

This insurance should cover the catastrophic event, where major damage/loss to the hydroplant occurs. Minor damage need not be covered since the hydro owner will probably have sufficient reserves to handle the loss.

To deal with the catastrophic loss, two alternatives have been considered. These alternatives are a Risk Retention Group (RRG) and a company specializing only in insurance for hydro/dam owners.

In late 1986 Congress acted to expand the Risk Retention Act of 1981 to facilitate the formation of a domestic captive insurance company. The Risk Retention Act of 1986 enables businesses, professionals, or any insurance buying group to pool and fund protection against their individual liabilities. To be viable the group must establish enough participation to generate an adequate premium base volume to support the endeavor. This new law addresses a broad range of legal liabilities including general liability, automobile, products, pollution, errors and omissions, and directors and officers liability. Workers Compensation and Employers Liability are not within the scope of the Act. The Act also significantly reduces the cost and time required to form an insurance company. Even though the Act is applicable to all states, individual state provisions must be observed if insurance coverage is to be established.

Considering hydro owners as the insurance buying group, it appears that the existing insurance industry will not easily be persuaded to provide the insurance needed by this group. It is conceivable that a Risk Retention Group, comprised of dam owners could provide this type of coverage to its membership on a self-insurance basis. However, the hydro owners would have to organize themselves and be committed to maintaining their projects in an insurable condition. In addition, the coverage limits are expected to be quite low, until sufficient reserves are established.

Another alternative is to have an existing insurance company specialize in insurance for hydro owners. The company would write insurance lines that specifically meet the hydropower industry needs. Initial steps have already been taken to form this organization. This approach has distinct advantages over an RRG, since insurance limits would be higher and management of the company would not depend on hydro owners. It is envisioned that the insurance company will participate in inspections and repairs of the dam and powerplant, in order to assist the owner in maintaining an insurable operation.

In either case, strict underwriting requirements will have to be met. It is anticipated that in most cases, hydro projects which comply with Federal Energy Regulatory Commission requirements for safety and operation would be insurable. The insurance will include floods, wave action and other perils that are normally excluded from property insurance. It is projected that the deductible will probably be in the range of $10,000 to $25,000. The insurance premium is expected to consist of three components. One part will be the cost to insure the risk. The second is to cover inspections of the hydro facility. The final part is an annuity component which will establish a fund to finance major repair/replacement of powerplant or dam components. With the annuity, the policy will have a cash value, increasing as time passes. When sufficient value is accrued, the insured will have first dollar coverage for catastrophic events.

Conclusions

Small hydro owners have major investments in structures and equipment and depend on reliable long term operation for financial success. Insurance is available for a wide variety of risks, however, it is often not well suited to the small hydro owner. Certain exclusions in property policies, such as flood and wave action, limit the value of the insurance to the owner. Although some specialized insurance brokers are now tailoring their coverage to hydro plants, dams are usually excluded. Liability insurance as well is limited in scope and does not generally meet the hydro owners needs.

Several alternatives for better serving hydro owner insurance needs are suggested, including a Risk Retention Group (RRG) and an insurance company specializing in the needs of the hydro industry. With either of these alternatives, the hydro owner will have to operate and maintain the operations in a safe and careful manner to be insurable. The underwriting of the projects will be intensive, including relatively long application forms and site inspections by the insurer. However, careful underwriting will be beneficial over the long term, since it is expected that insurance rates should drop with favorable claim experience.

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SESSION 6:

PROJECT FINANCE - INTERNATIONAL 1

Chairperson: G. Tadros
Infastructure Division, CIDA

UNIDO Activities in Small Hydro Power and Related Aspects to Industrialization

By
J. Furkus

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UNIDO ACTIVITIES IN SMALL HYDROPOWER AND RELATED ASPECTS TO INDUSTRIALIZATION

by

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UNIDO ACTIVITIES IN SHP AND RELATED ASPECTS TO INDUSTRIALIZATION

1. Introduction:

The introduction and application of SHP in developing countries is an integral part of UNIDO's energy related technical assistance activities and contributes to the process of industrialization.

The importance of energy and energy-related technologies to the industrial development of developing countries emerged in the context of the Lima Declaration and Plan of Action on Industrial Development and Co-operation resulting from the Second General Conference of the United Nations Industrial Development Organization held in 1975.

The Third General Conference of UNIDO, held at New Delhi in 1980, referred specifically to energy in the process of industrialization. It stressed that the development of new and renewable sources was required in addition to the continued utilization of conventional sources of energy. Attention was also called to the need to rationalize the consumption of energy at the global level, particularly by developed countries. The New Delhi Declaration and Plan of Action on Industrialization of Developing Countries and International Co-operation for their industrial development contains a number of recommendations specifically related to energy.

As a follow-up to the UN Conference on NRSE in Nairobi in 1981 and UNIDO's 4th General Conference in Vienna (1984), growing attention has been given to the development of technical co-operation projects in hydro-power, biomass, solar and wind including the support for regional co-operation and exchange of information particularly among developing countries and the promotion of local design and manufacture of equipment. However, compared with the requirements and possible application of SHP technologies for the exploitation of the world's hydro-electric power capacity the utilization of SHP is not predominent, specifically in developing countries. This shows the great potential and need for joint efforts to accelerate the transfer of know-how and to promote the development of technological capabilities and human resources in the field of SHP in line with local priorities using the system of international co-operation.

2. Energy, SHP and Industrialization:

2.1 Considerations on Energy/SHP Resources and Requirements and Interrelation with Industry

The major purpose of UNIDO is to promote and accelerate the industrialization of developing countries. In support of that role, UNIDO performs its mandate as the 16th specialized agency of the United Nations System on the basis of its constitution which came into force in June 1985 and through the realization of appropriate programmes and technical assistance activities, which are due to facilitate the fulfilment of its functions.

Energy is of crucial importance to the industrialization process and the efficiency, scope and technological level of industrial development with its economic, technical consequences and social implications depends to a large extent on the effective introduction and application of related technologies.

Despite of the slow-down of the economic growth, if compared with previous years, and the efforts towards a more rational and sparing use of energy, it is assumed that the demand for energy during the forthcoming decades will continue to grow on a worldwide basis although differing among countries according to specific conditions and policies. The share of developing countries in the world's energy consumption needs was nearly 15 % in 1980 and is expected to grow up to 27 % in the year 2000 and 40 % in 2020 according to the World Energy Conference held in 1980. Following these figures and assessments of the 13th Congress of the World Energy Conference in 1986 it can be stated that the developing countries will have an above-proportional growth rate of their demand for energy in future.

In the light of the increasing dimension of energy consumption and the limitation and unequal distribution of the most effective conventional energy resources it is necessary to diversify energy sources mobilizing alternative sources on a substantive scale.

Projections on the future share of renewable energy sources in the total balance of energy supply vary from each other. The share, however, is growing and shall reach 10 - 15 % in the year 2000 following the predictions of the UN Conference on NRSE (Nairobi, 1981).

Among NRSE, above all hydro-power, biomass and solar energy are likely to make significant contributions to the overall demand for energy from the industrial sector of developing countries on short and medium terms.

The estimated world's potential hydro-electric power capacity is about 2.2×10^6 MW. Approximately 60 % of this potential exists in the less developed countries of Latin America, Africa, Asia and the Pacific Islands. However, compared with the requirements and potential resources the utilization of hydro-power, especially that portion below 5 MW capacity is largely underdeveloped. Only about 16 % of the total technically usable hydro potential in Asia and about 13 % of the corresponding rate of utilization in South America have so far been harnessed. For Africa, the corresponding proportion is only 4 % compared to 94 % in Europe. Mini-hydro projects (under 1 MW) might comprise 5 - 10 % of the world's total hydro resources.

For effective and sustained industrial develpoment, energy production and utilization must be planned with other factors, such as technology, human resources, raw materials and finance.

The interdependence of energy and the industrial sector is of major concern for governments of developing countries in formulating both energy and industrial policies. Industry is a major market for energy, and developments in industry closely affect the energy sector, just as developments in the energy sector affect industry. The size and structure of the industrial sector determines the amount and type or form of energy needed. Similarly, the availability and cost of energy supplies has a major influence on industrial development.
The Lima target, namely that developing countries should achieve a minimum of 25 % of world industrial output by the year 2000, requires for its achievement correspondingly massive inputs of energy.

As an indication of the energy implications of industrialization in the near future, estimates made by UNIDO of the energy needed to achieve the Lima target show that the energy requirements of the developing countries would have to increase from 1,600 mln tonnes oil equivalent (mtoe) in 1975 to some 6,500 mtoe by the year 2000.

The energy reserves and resources necessary for this increase are available if all sources of energy, and not only oil, are considered. In fact, it was proposed at the United Nations Conference in New and Renewable Sources of Energy held at Nairobi that up to 50 % of the increased energy requirements of the developing countries be covered by new and renewable sources of energy. Achieving this calls for a major effort covering all forms of energy, conventional and otherwise new and renewable, and requires, in turn, both financial and technological support at all levels and co-operation in all forms, including trade.

Industry is a major consumer of commercial energy in the developing countries. It has been estimated that the average for all developing countries is around 35 % but there is, of course, wide variation between countries. The manufacturing sector is the major user of industrial energy, accounting for between 20 and 45 % of total energy consumption. Currently the developing countries have to import some 60 % of their commercial energy. This has an obvious and serious effect on their balance of payments.

In view of the above, small-scale hydro-power plants in the range from 10 KW to more than 5000 KW can increasingly become an economically viable and reliable source of energy specifically for rural and isolated areas and there are quite a lot of countries, including those from the third world where the availability of SHP and its application has proved to be an effective means to promote industrialization, rural electrification and mechanization, economic and social development.

A survey of SHP capacities in some developing countries is given in Table 1 overleaf.

Table 1: Survey of exploitable capabilities, operational and planned capacities of small hydropower schemes (installed capacity less than 1 MW) in some developing countries.

Country name	Year of Refer.	Exploitable Capability* (GWh)	Capacity Operational (MW)	Planned (MW)
Argentina	1984	38	7	11
Burundi	1984	U	3	0.86
China	1984	210,000	9,060	71.300**
Cyprus	1982	23,500	0,65	0.9
Indonesia	1984	U	15.64	U
Jamaica	1984	U	0	2.5
Jordan	1984	14	U	U
Korea (Republic of)	1984	U	1.85	17.85
Malaysia Sarawak	1984	U	3.22	27.11
Mexico	1984	U	69.4	U
Nepal	1983	U	U	1.27
Philippines	1984	U	1.2	U
Portugal	1984	15,000	-	6,000
Sri Lanka	1984	263	1	3.5
Taiwan	1984	U	3.3	10.6
Thailand	1984	U	2,846	20.893
Venezuela	1984	U	23.31	0.415
Zambia	1984	8.76	0.75	0

Source: World Energy Conference, Survey of Energy Resources 1986.

Note*: Exploitable capability for small hydro power schemes is the total annual energy which could be exploited for small-scale hydro plants within the limits of current technology and under present and expected local economic conditions.

Note **: Exploitable capacity

U: Denotes unavailability of information

2.2 SHP in Rural Areas

Developing countries are faced with growing problems of energy deficiency, particularly commercial energy resources for rural development accompanied by a depletion of non-commercial/traditional sources and negative effects on the environment (deforestation, soil erosion) and the country's social and economic status.

This situation calls for an integrated and long-sighted approach to the use of all promising forms of energy specifically NRSE and SHP as a major component with a great potential for agriculture, rural and small-scale industry.

SHP can be used for the production of electrical and mechanical energy required for community electricity supply, water pumping for domestic use, livestock and irrigation, for crop processing, threshing, grinding, milling, etc. and agro-industry. SHP units are very well suited to replace diesel generators, to complement existing grid supply or to provide electricity for remote decentralized installations.

The relatively large capital requirements at the initial stage and the low load factor in rural areas (which may vary from 0.10 to 0.25 compared to perhaps 0.50 in urban areas of developing countries) are of crucial importance to the economic viability of SHP schemes since a high utilization factor can keep the unit costs down and vice versa. Table 2 (Ref. No. 25) is reflecting this accordingly.

Table 2: Total electricity generating costs of small hydroelectric plants

Load factor (%)	Discount rate (%)	Total cost ($/kWh)		
		$ 1,000/kW	$ 2,000/kW	$ 3,000 kW
40	5	0.04	0.07	0.11
	10	0.05	0.09	0.14
	15	0.06	0.11	0.17
30	5	0.05	0.10	0.15
	10	0.06	0.12	0.18
	15	0.08	0.15	0.23
20	5	0.07	0.15	0.22
	10	0.09	0.18	0.27
	15	0.11	0.22	0.34

For comparison a 1.000 kW diesel generator with $ 700/kW capital cost, 15 years life time, 45 % load factor and $ 0.5 fuel cost per litre would have generating cost of around $ 0.14/kW at 10 % discount rate. The need to provide electricity from SHP at reasonable costs must not be underestimated. Rural electrification, however, remains a prerequisite for development and SHP should play a growing role. Energy planning, SHP and potential other renewable sources of energy like biogas and solar must, therefore, be integrated into rural development plans bearing in mind economic, technological and financial consequences, as well as social implications.

3. Technical Assistance Activities:

3.1 Energy/NRSE related TA activities and SHP

Statistical data on UNIDO's disbursements on energy, NRSE, SHP are given in Annex 1 and 2. UNIDO delivers yearly about US$ 100 mln of technical assistance. 10 % of this assistance is related to energy. In the year 1980 it was only 5 % (Annex 3). The increase of the NRSE share is even more impressive as reflected in Annex 5. In the year 1980 the NRSE share amounted 0.5 % of UNIDO's technical assistance. By the end of 1987 an almost constant NRSE share of 3 % can be recorded. Annex 5 illustrates this development comparing NRSE with the total energy disbursement in UNIDO's TA programme.

A breakdown of UNIDO's NRSE disbursements by region and source is given in Annex 6 covering the period 1980 - 1987.

The development of UNIDO's technical co-operation programme on SHP since 1980 is shown in Annex 7 with a total of 27 completed or ongoing projects with a total expenditure of around US$ 4,042,000 between 1980 and 1987. Increasing attention is paid to the least developed and the African countries. Priority areas of the SHP programme are:

- Planning and integration of small hydropower into rural industrial development;
- Pre-feasibility and feasibility studies;
- Designing of small hydropower plants, including civil engineering;
- Technological development, technology unpackaging and standardization of components and systems for local manufacturing;
- Support of regional co-operation and exchange of technical information;
- Investment promotion;
- Training, organization of workshops and seminars, fellowships, studytours and on-the-job training.

At an earlier stage the main scope of UNIDO's assistance was aimed at encouraging developing countries in the application and local manufacture of small hydropower for rural industrial development by creating regional networks for co-operation in research and devleopment and organizing workshops, training courses, seminars and study tours.

As a consequence of the growing interest in developing countries on active programmes, UNIDO's assistance is now concentrated on the implementation of small hydropower schemes in individual countries.

Technical co-operation in SHP must, indeed, be focussed on strengthening the developing countries own technological capabilities and resources. Reviewing, however, technical assistance activities from the contents point of view and with regard to the objectives to be achieved even more official requests for technical assistance in SHP development and more projects with real implications to the upgrading of the quality of life and economic well-being of people in developing countries and concerned communities seem to be needed. Conferences like this can contribute to the process of creating a greater awareness of the need and possibility for more practical projects or ideas and concepts which may lead to viable project proposals.

3.2 Selected SHP Projects:

3.2.1 The Asia-Pacific Regional Network for Small Hydropower (RN-SHP) and the Regional Centre for SHP at Hangzhou (HRC)

UNIDO has been actively involved in project activities related to the establishment of the "Regional Research, Development and Training Centre for Mini-Small Hydro Power Generation" in Hangzhou, China, to function as the focal point of a network of national Mini-Hydro Power generation organizations/institutions determined by the individual member countries of the region. This project (DP/RAS/80/033) covers a total UNDP component of approximately US$ 700,000 with roughly US$ 95,000 for expertise, US$ 190,000 for training and US$ 305,000 for equipment and is being carried out in conjunction with two other projects subcontracted to UNIDO by ESCAP/REDP* namely DU/RAS/84/001 and DU/RAS/86/136 totalizing US$ 370,000 and DP/CPR/81/004 with a UNDP input of US$ 352,000 respectively. The total sum of these projects is about 1.5 mln US dollars, in which approximately 31% was used for equipment, 29% for training/workshops and the remainder for other activities (expertise, etc.).

The Chinese Government has also paid great importance and has given substantial support to the establishment of the Regional Centre for SHP at Hangzhou. The total amount of funds allocated from the Ministry of Water Resources and Electric Power to the HRC was equivalent to US$ 2.4 mln for capital investments of the buildings and salaries and overheads.

A 14 floor building of the HRC with 6000 m^2 is quite well equipped including video-audio equipment, language laboratory, simultaneous interpretation systems and other equipment and can be used for various activities in the Regional Network Projects particularly in the fields of training, information and consultancy.

The RN-SHP work programme for the period 1987-1991 which was prepared during the Second Technical Advisory Group (TAG) Meeting held in October 1986 in Penang, Malaysia, includes, for instance, five training workshops, five research and development (R + D) projects, four expert group meetings to assess the R + D projects, two consultation missions, four missions of the TAG and the RN-SHP newsletter.

R + D projects will cover areas of socio-economic impact studies of SHP, planning and design guidelines, standardization of civil and electromechanical equipment, local manufacturing of SHP equipment and unmanned and remote operation of SHP stations and grid systems.

There will be training workshops on socio-economic aspects of SHP development, construction management of SHP development, and watershed management and environmental impact assessments.

In addition to this work programme, the Network plans to undertake other activities. One of the projects of the Network is to compile a roster of SHP experts, research organizations and equipment manufacturers. Research and development and training activities can be conducted by countries which meet the required facilities.

The RN-SHP also plans to establish linkages with other networks and organizations that are engaged in activities related to SHP.

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* Regional Energy Development Programme

In summary, both the facilities and experience gained at the HRC has been and will be further increased to a higher level so that the Regional Centre for SHP can fulfil its function as a Centre of excellence for training, co-operative research and development, information and advisory services in SHP.

3.2.2 Hoha Mini Hydropower Project in Africa

The Hoha Mini Hydropower project SI/ETH/85/803 refers to the development of a MHP plant in Ethiopia. The project site is located about 750 km to the southwest of Addis Ababa. The plant shall provide the regional centre and border town of Asosa with energy produced by hydropower. Due to its remote location the Asosa region is not integrated in the national electrical grid. The MHP plant is basically a run-off-the-river scheme, located on the right bank of Hoha river, near the waterfalls, consisting of a diversion weir with intake, about 2.4 km of open head race canal, forebay, 265 m of penstock route and a powerhouse for two units with an installed capacity totalling 650 kW. The project includes 6.5 km of new access roads, housing for staff and about 10 km of transmission line. Hydrological data indicate that a flow of 0.3 m^3/s is guaranteed 90 % of the time to be translated into electricity under a head of 135 m. The main characteristics of the Hoha Hydropower Plant are reflected in Annex 8.

The objectives of the project are:

- to encourage rural industrialization using local manpower and manufacturing resources through the development of mini-hydropower;
- to analyse available studies on mini-hydropower generation with the aim to identify ways in which they can be implemented at low cost, utilizing local manufacturing capacity to the fullest possible extent;
- to prepare engineering plans for the project including the rehabilitation of existing turbine generator set from a shut-down MHG plant;
- to identify small-scale rural industries that could utilize the energy made available by the project.

It was further considered to base the power plant technology as far as possible on the level of technology prevailing in local industries and to stimulate the local manufacturing sector to improve their technology and participate in the production/adaptation/rehabilitation of MHP equipment.

After installation of the first set with a capacity of 300 kW which is scheduled to be commissioned in 1988 in Phase 1, a second unit of 350 kW is required in 1989 in Phase 2, in order to cope with the forecast increase in demand. In Phase 3, a dam may be added to increase availability of the plant. The economies expected from the dam may also benefit from irrigation, which could be implemented downstream of the power plant, making use of the regulated flow, especially during the dry season.

The technical work during the design phase was conducted as teamwork involving in all disciplines local experts and their counterparts in a way, that a full technology transfer would occur.

The training on-the-job aspect was observed and use was made of the planning capabilities inherent in the team. Also, during conception of the structures, efforts were made to utilize local manufacturing capacity to the fullest possible extent.

Thus, the hydro-mechanical equipment was provided for local manufacture, including part of the penstock. The civil structures will be executed in masonry from natural stone available in the area. Reinforced concrete will only be used where unavoidable. The whole head-race canal is foreseen to be built with local manpower and manual labour. All repair and erection work for the various components of the project will be executed using local skill, including the rehabilitation of the existing turbine-generator and its accessories.

The results of the economic analysis have shown that the energy to be expected from the mini-hydropower plant can easily be absorbed in Asosa and that hydropower would be less expensive than diesel power which in addition to its high price is import-dependant. It can also be deduced from the economic analysis that all three project phases should be implemented in the shortest possible time.

However, the project budget available at the time of review work in 1986 did not allow to cover all engineering services required for the implementation of the project specifically with regard to detailed engineering related to the construction work and the irrigation aspect including the dam design and the layout of the irrigation scheme so that further assistance is needed to complete the project as scheduled.

With respect to the development of local manufacturing capacities it was, among other things, recommended to:

- Establish a range of cross-flow turbines adequate to the most frequent applications in the country for local manufacture and start a turbine production with small and simple units using existing experience and facilities;
- Manufacture locally hydro-mechanical components like gates, trashrack, part of the penstock and develop a suitable type of governor which can be produced in series involving, if necessary, an experienced manufacturer abroad during the initial production phase;
- Extend gradually the range of turbines into bigger size and higher heads in parallel with the increase of production capabilities;
- Start at a later stage, probably after the production of electric motors has been taken up in the country the manufacture of small generators for the combination with the cross-flow turbines locally produced.

It was estimated that a local manufacturing capacity for a limited range of cross-flow turbine units could be set up in less than five years on the basis of coordinated efforts. Cross-flow turbines were recommended because they are quite suitable for local production as generally known since the rotor and casing can be made from sheet steel and the requirements for welding, turning, grinding, etc. are moderate whereas Kaplan, Francis and Pelton turbines require relatively highly developed casting, forging and welding techniques.

3.2.3 Small-scale hydropower in Island Countries

As an example, reference is made to hydropower projects in the Solomon Islands. Studies have shown that this country has a great potential for the development of small, micro and mini hydropower capacities. The annual rainfall in most land areas is 3,000 - 5,000 mm distributed throughout the area. The present installed power capacity in the country is only about 8,000 kW, almost all of which is generated by diesel plants and at present only 11% of the total popultation have access to electricity.

In 1986 under the project SI/SOI/85/802 assistance was given in formulating a development programme on MHP projects. A technical report was prepared recommending, among others, four projects for immediate development. Three of them are in the range of 100 kW and one of 6 MW capacity. It was also proposed that the three 100 kW plants be developed as pilot mini-hydro schemes with top priority for one of them, thus providing an opportunity for the Solomon Islanders to gain experience and training in engineering design, construction and operation of MHG plants. The report also advised on future work to get the projects implemented.

However, a micro-hydro-electric pilot plant was installed in 1983 under the project US/SOI/83/076 sponsored by the Australian Government through the special purpose contribution to UNIDF and follow-up activities were arranged in 1985/86,mainly in repair, maintenance and training.

The purpose of the project was to initiate the construction of a micro-hydro-electric power generating plant in the village of Iriri on the island of Kolombangara in the province of the Western Solomons and to implement it as a pilot project for future applications throughout the Solomon Islands Republic, thus encouraging rural industrialization using inherent skills and local resources. In the course of project implementation local people had to be trained in planning, constructing, installing, operating and maintaining such power generation systems to that the hydro scheme can be used in line with the needs of the Iriri community.

The main components of the system consisted of:

- the village reticulation, i.e. housing wiring for lighting, and selected power points in community structures for cottage and light industry;
- the electrical transmission of electricity from turbine to the village by a 1.3 km underground double-insulated cable;
- the civil hydraulic construction (dam, penstock etc.). The pipeline of approximately 1 km for conveying the water to the turbine was constructed of high-grade UPVC, treated for an indefinite lifetime in tropical environments and supported by a timber structure from the damsite;
- the turbo-generator unit consisting of a Pelton wheel turbine attached by a belt-drive to a 12 kVA Dunlite self-excited brushless single-phase alternator.

The use of brushless alternator was considered mandatory to meet the low-maintenance requirements set by the design criteria.

The Pelton wheel design for the turbine was selected with the long-term objective of local manufacture.

Although fully up-to-date figures on Iriri's returns from its electrification are not available, several economically measurable sources of returns related to wood-processing, craft production, guest accommodation and fuel replacement battery charging, indicate the scheme's numerous benefits. Following the figures of the final report the annual economic return attributable to the hydro scheme is at least $ 7,500.

The scheme would, if repeated, justify itself on a standard bank-loan basis, in that yearly income exceeds loan repayments from the outset. The so-called payback period, if defined as the time taken for income to exceed capital costs, should be less than four years.

The project has proved to be a justified initiative in the field of micro hydropower development. It has indicated the right approach to design of the Iriri scheme, verified its pilot character and has shown its demonstrative effect. However, subsequent decisions for a more widespread implementation require appropriate policies and mechanisms of interested governments and should take into account basic lessons from the Iriri pilot project and conclusions as outlined in the Final Report.

4. Engineering Aspects of SHP Projects

4.1 Advantages and limitations of SHP

As a matter of fact, on a world-wide basis, both the need and the market exist for large numbers of mini and even micro hydropower plants. Hydropower is, however, site specific and beside all endeavours towards standardization each type of project, depending on the power range requires a different approach, its own design philosophy and different standards for construction. Plants with a capacity of more than 1 MW require, as a rule, full studies, expert design and experienced contractors, whereas micro-hydro schemes mostly follow simplified construction techniques with a maximum of local input. Small mini-hydro plants in the range of 100 to 1,000 kW are often a compromise between both extremes with a tendency towards the simplified design and construction techniques of micro-hydro.

In any case a realistic approach is required to make the best use of the specific advantages of SHP plants. Today SHP is generally based on a well developed technology adaptable to local conditions. MHG plants can quickly be built, compared to large hydropower installations, have low operating costs, long service life, if properly designed, manufactured and constructed, have little adverse environmental impact and require cheap and simple maintenance. SHP opens up increasing possibilities for the use of indigenous materials, equipment, local skill and manpower.

However, although well developed there is still room to improve the state of the art of small-scale hydro technology. Mechanical and electrical equipment must often be individually designed to overcome the unique problems of each site and to optimize the available potential.

Turbine technology is mature. Many of the newly designed turbines have seldom substantial advantages over traditional turbines.

Nevertheless, SHP is still a challenge to its designers. It offers a wide range of options, innovative ideas and new concepts for systems of low costs and high efficiency by a combination of functions from different designs.

As far as standardization is concerned it is generally recognized that standard turbines, i.e. the production of a range of units of identical design is specifically applicable to mini and micro turbines where cost is important and where the efficiency might be considered of lower priority.

Electrical systems should also be standardized wherever possible to ease the load on maintenance, to minimize spares holdings and to encourage local manufacture. Because even a large variety in the ratings of electrical equipment will not lead to excessive costs or deterioration of efficiency, it is not so difficult to design a limited range of standard control and protection systems, switchgear and transformers which are suitable for outputs from a few hundred kilowatts or even less and up to several megawatts.

SHP has also disadvantages like (a) high unit investment costs per installed kW which varies considerably (US $ 1,000 - 5,000 per kW) depending on head-, site -, and other local conditions, (b) high study costs in relation to overall investments and (c) the prospects for the continued operation of the plants depending, for example, on hydraulic resources, meteorological and seasonal conditions, etc.

Several attempts have been made to reduce these limitations. New ideas are mainly aimed at changing the traditional concepts of preparing and implementing SHP plants avoiding, if possible, or minimizing the necessity for detailed analyses and optimization procedures to ensure availability of power at the earliest possible date. Economic analysis, for instance, can sometimes be limited to direct comparisons with diesel generation. Other approaches are oriented towards the application of standardized equipment, the utilization of pre-fabricated and/or pre-assembled units and components, the development and introduction of low-cost designs and simple technology to ensure a maximum local participation in equipment production, plant construction, reliable operation and an easy maintenance and repair.

In order to follow simplified approaches it is essential for the design of the installation to have sufficient and reliable input data on the water flow, topography, technical specificiation etc. since site, loading and operating conditions determine the engineering design and application of MHG plants.

4.2 Local manufacture and technical requirements

Considerable savings are possible if locally fabricated equipment is used. However, this requires the availability of local know-how and appropriate production capacities, adequate workshops or at least multi purpose production units which may also be considered for manufacturing components or sets of hydropower equipment.

Local manufacturing capabilities should be developed gradually and in line with national programmes and priorities by mobilising indigenous resources and intensifying international assistance including technical co-operation among developing countries.

Problems of local manufacturing should in no way be underestimated. A potential market, viable SHP sites, engineering plans, machinery and funds are necessary but not sufficient prerequisites for the production of SHP equipment. In order to produce and install SHP plants up to the international standard very well-trained engineers and technicians with practical experience in SHP technology as well as skilled personnel at the shop level, such as machine operators, welders, mechanics, fitters, plumbers, electricians and carpenters are required. In addition, a gradual involvement of local organizations and companies in production processes of SHP is necessary and more pilot plants must be materialized to enable developing countries to get their own experience and to develop their local know-how in the design, manufacture, operation, repair and maintenance of complete SHP sets or components and to establish their national engineering resources and consulting services.

The practice has already shown that in countries with large SHP potential engineering capabilities can successfully be developed by utilizing local resources. On the whole, however, the establishment of local design and manufacturing capacities is still rather slow.

The conventional approach of utilizing deliveries and services from industrialized countries which includes, for instance turn-key delivery of equipment remains probably dominating in countries with limited potential of viable SHP sites. It may also be applied to countries which enter the SHP scene, so to say as an intermediate stage to bridge the gap until domestic manufacturing capability exists. This would enable practical training of national experts in SHP development including planning, design and construction work, operation, repair and maintenance of SHP plants thus encouraging the involvement of indigenous resources in follow-up projects.

As far as technical requirements are concerned, machinery, i.e. machine tools and instruments for the local production of SHP component parts, has to be specified in line with the type of SHP equipment needed. As a general approximation well-equipped workshop facilities are required consisting of a combination of different types of machines including lathes, drilling, cutting bending, grinding, milling, shaping machines and special equipment for welding winding, casting, forging, balancing, lifting, testing and measuring. Furthermore, appropriate materials and semi-manufactured goods are needed like sheet metal, steel bars of various profiles, welding rods, non-ferrous metals, insulating materials and standard smaller component parts for a mechanical or electromechanical workshop.

The capacity of SHP plants are mainly determined by the stream flow and head. Unit costs rise rapidly as power ratings decrease and plants with low heads are more costly than those with high heads (in the proportion of 3:1 for heads of 5 and 200 respectively). Real costs of SHP plants have to be analysed in each individual case. However, referring to figures from a well established manufacturer of small scale hydraulic turbines and related equipment the following breakdown of cost may be given to characterize the overall cost factors for SHP plants:

- Production and installation of metal component parts (including the pipeline and related metal parts) : 10 - 20 %.
  (This part of the work can be executed by a company experienced in the production of metal hardware, e.g. steel structure, pipework, if supported by a company experienced in the construction of SHP).

- Production and installation of turbine: 20 - 30%.
  (Experience in the construction of SHP is necessary, or at least a close co-operation in a process of gradual transfer of know-how from a company experienced in SHP plant construction).

- Production and installation of electrical parts: 15 - 30%.
  (This part of the work can be executed by a company experienced in the production of medium-sized electric motors and switch gears, if supported - at least for some time - by a company experienced in the installation of SHP plants).

- Local civil works: 30 - 60 %.
  (This part of the work can be executed by a local company experienced in the setting up of SHP stations).

From the same source it is indicated that the overall cost of maintenance of an SHP plant during its life-span of about 30 - 40 years and even longer if properly maintained, amounts to approximately 10 to 20 per cent of the construction and installation cost of the respective SHP plant.

Repair and maintenance, spare parts supply and/or production of spare parts should be considered as an integral part of each SHP project. Effective repair and maintenance services can be considered as a means of the entry into the manufacturing sector and to build up local skills. Major equipment repairs require specialized workshops and competent maintenance personnel. Preventive maintenance, minor emergency and general equipment repairs or general repairs to the civil engineering structures may be handled by qualified operators with the support of the community or utility.

There are general recommendations or maintenance procedures from the manufacturers side on the cycle of necessary repair and maintenance work. These recommendations are related to the individual components of SHP plants including civil constructions and electromechanical equipment and should be followed thoroughly.

5. Technology Transfer and Co-operation with Developing Countries

5.1 Transfer of Technology and Procedures for Technical Assistance:

UNIDO in its endeavours to assist developing countries in SHP application and to facilitate the flow of know-how promotes the transfer of technology through:

- studies and publications on SHP technologies;
- the exchange and publications on SHP technologies;
- the exchange of experience using expert group meetings, study tours, regional networks;
- training in various aspects of SHP;
- advisory services by consultants, experts, etc;
- co-operative programmes of applied R + D of SHP between countries regions;
- the establishment of prototypes and demonstration units;

One of the most effective ways to acquire up-to-date technologies is the practical implementation of SHP schemes and the development of appropriate design, production and training capacities stimulating local participation and inherent skills.

The scope of the local content of SHP projects and the respective technology package to be transferred depend on the availability of indigenous engineering and consultancy capabilities.

SHP technologies to be introduced to developing countries should be mature, as simple as possible, reliable and safe in operation with low investment requirements and adopted or adoptable to the local needs using, whenever possible, indigenous equipment, raw materials and human resources.

However, a defined policy for the implementation of SHP plants is needed as part of a national strategy in NRSE, national experts with appropriate qualifications, financial resources and, of course, the know-how are required to accelerate SHP application in developing countries. International co-operation and technical assistance can effectively contribute to the transfer and adaptation of technologies concerned.

UNIDO provides technical assistance related to the whole cycle of SHP projects including:

- the preparatory phase (hydrological studies, feasibility studies, project design and engineering, etc.)
- the implementation phase (off-site activity like design and production of equipment, quality control/testing and on-site activity including civil works, construction work, installation/assembly of equipment, etc.)
- the exploitation phase (operation of SHP equipment, spare parts production, maintenance and repair)

and the transfer of complete technology packages or specific parts to be acquired by the respective project.

In order to get technical assistance from UNIDO some procedures should be followed.

Technical co-operation is based on the concept of a tripartite partnership between a participating Government, UNDP and UNIDO. UNDP is represented in most developing countries by a Resident Representative who is responsible for the co-ordination of all UNDP activities in the country. In some countries, a UNIDO representative (Senior Industrial Development Field Adviser/SIDFA) is assigned to the office of the UNDP. The SIDFA is responsible for UNIDO matters in that country, in particular to generate new projects and follow-up on existing ones bearing in mind Government priorities.

The recipient Government is a full partner in the tripartite arrangement. As a rule, recipient Governments designate one of their central authorities to co-ordinate Government participation in UNDP/UNIDO technical co-operation programmes; this authority is usually referred to as "Government Co-ordinating Unit".

UNIDO, as an executing agency, is the third partner in this arrangement. With UNDP providing the financial inputs under the "Country Programme", UNIDO, in co-operation with the host Government, is the executing agency responsible for programming, formulating and carrying out the project activities. The executing agency, UNDP and the Government may undertake a tripartite evaluation of activities in particular sectors, sub-sectors or areas with a view to identifying specific problem areas which require a reformulation of the project and preparing new programmes.

The following steps are usually required to initiate a technical assistance co-operation project:

The first step is for the requesting department or ministry in the Government to contact the UNIDO Senior Industrial Development Field Adviser (SIDFA) or the UNDP Resident Representative (RR) in the country, explaining as detailed as possible the technical assistance required. The requesting Government should identify the entity responsible for the project (Government Implementing Agency), the local services and facilities which will be made available and the financial resources if any which will be provided to the project (cost-sharing).

Following these preliminary steps, a draft project concept should be prepared jointly with the local SIDFA and forwarded to the UNIDO secretariat for technical review and elaboration into a full-fledged project document according to the established guidelines using the expertise available with UNIDO or/and international experts or international firms depending on the nature of the project. The project document will then be forwarded to the Government and UNDP for approval and signature.

After the approval the project will be implemented by UNIDO in co-operation with the Government Implementing Agency in accordance with an established work plan.

5.2 Promotion of Technology and Information Exchange:

UNIOD's promotional activities include the publication and dissemination of documents related to SHP including country papers, technical reports and documents of general interest, such as:

- Mini Hydropower Stations / A Manual for Decision Makers (Ref.No.7)
- Chinese Experience in Mini Hydropower Generation (Ref.No.12)
- Guidelines for the Application of Small Hydraulic Turbines (REf.No.15)
- Report on Standardization for Indigenous Manufacturing of Small Hydroelectric Power Plants (Ref.No.24)

UNIDO has quite good experience in the field of industrial information and has, for over 20 years, been active in providing computerized information packages and in establishing information networks on specific topics including NRSE and SHP as a major component.

The exchange of technological information plays a quite important role and UNIDO is aware of the necessity to avoid duplication of responsibilities and efforts. Therefore, the UNIDO's Energy Information System (EIS) has been created, in order to provide support for the Organization's energy programme and to record its energy activities.

The system's key components are:

- PRAD DATABASE

This necessity for reporting on UNIDO's own activities in the energy sector led to the creation of a computerized information system covering project and other energy-related activities, which has been expanded with the passing years and gained in complexity and coverage. Almost five hundred energy projects have been under implementation since 1980 and form a part of the PRAD computer programme (one component of the EIS). This database provides information on project activities, giving standard data on project number, title, financial aspects, counterpart agencies, as well as an abstract on each project's scope and coverage.

- IDA DATABASE

The IDA (Industrial Development Abstracts) database records, inter alia, technical and final reports which stem from projects, thereby providing a complementary source of information on energy project activities. This existing database is also utilized for providing information on what UNIDO has been doing in the energy sector including SHP.

- ENER DATABASE

This system primarily provides support for INECA (Industrial Energy Conservation Abstracts) which covers information on several activities related to energy conservation in industry, i.e. abstracts of technical papers, energy efficient technologies/equipment, training opportunities, research and development, meetings and consultants/experts. This database will also be available in micro form by mid 1988. The INECA data base is the core of an initiative for creating an information network on industrial energy conservation.

Resulting from a UNDP supported project in the European region, the network concept has found an echo in other regions - initially ASEAN and the Caribbean - and with other organizations. Activities will include utilization of electronic mail for information exchange and the initiation of information exchange modalities between interested parties/nodes within each region and between regions. Envisaged output of the INECA network information structure are manuals/guides on energy technologies and activities related to them, e.g. solar energy and energy conservation in specific sectors; information on UNIDO's energy activities; newsletter INECA and information packages on selected aspects of energy/industry.

6. Conclusions

(1) The acceleration of the industrialization process, the increase of agricultural production and the improvement of living conditions in developing countries requires a well balanced development of the energy sector and their own technological capabilities and human resources in line with national priorities. The mobilization of the indigenous resources and a close international co-operation on the basis of equality and mutual benefit are key factors in this respect.

(2) The demand for energy, particularly electricity will further increase in the future. The developing countries will have an above-proportional growth rate in their energy demand. The share of NRSE in the total balance of energy is growing and hydropower, specifically SHP can make a significant contribution to the energy supply of the industrial sector and agro-industry of developing countries on short and medium terms.

(3) Small-scale hydropower has become an increasingly viable and reliable source of energy with great potential for rural and isolated areas. The developing countries' growing problems of energy deficiency require however, a long-sighted approach to the use of all indigenously exploitable forms of energy including NRSE and SHP as a major component for the promotion of rural development and small-scale industry. SHP must, therefore, be integrated into national development plans taking into account economic, technical and social implications.

(4) The described projects on small-scale hydropower, i.e. the Asia-Pacific RN-SHP and the Regional Centre for SHP at Hangzhou, the Hoha Mini-Hydropower Project in Africa and the Iriri Micro-Hydroelectric Pilot Plant in the Solomon Islands can be regarded as examples several elements of which could be applicable to projects in other regions and countries of the third world particularly with regard to:

- the set-up of regional networks for SHP (RN-SHP/HRC),
- the approach of establishing local manufacturing capacities (HOHA),
- the introduction and application of microelectric development schemes (IRIRI),

promoting the process of industrialization and rural development.

(5) Mature SHP technologies of simple design, reliable operation, low costs, high local content of equipment and materials and adaptable to local conditions have the most promising potential to be applied in developing countries particularly in cases where a whole spectrum of indigenous labour is involved. Local manufacture requires, depending on the SHP components to be produced special knowledge in general mechanical engineering (casting, forging, welding, metal-cutting) and special mechanical engineering with regard to hydraulic systems, governors, penstock, shut-off devices and special electrical engineering (generator, switchgear etc.). Most of these engineering fields are, however, not SHP specific but of multipurpose nature and must be seen in the general context of industrialization. This facilitates the process of entering the manufacturing sector in SHP, using among others, existing workshops or production units and extending available facilities up to the required standard.

(6) Technical assistance activities in SHP should be focussed on the practical implementation of SHP schemes (pilot and demonstration plants) in developing countries and the development of appropriate capacities for local design, manufacture/assembly, R + M, rehabilitation of SHP plants and related equipment through the promotion of the transfer and adaptation of technology, training, exchange of experience and information, co-operative programmes between industrialized and developing countries as well as among developing countries. The involvement of international organizations like UNIDO can facilitate the process of introducing SHP technologies using existing mechanisms and established procedures.

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YEARLY/REGIONAL DISBURSEMENT ON ENERGY
IN THOUSANDS OF US$

	1980	1981	1982	1983	1984	1985	1986	1987	TOTAL
Africa(sub-Sah)	1,330.7	1,496.5	1,614.0	1,378.7	2,326.8	2,147.7	2,069.8	1,449.4	13,813.6
Asia/Pacific	1,627.7	1,310.3	3,160.6	2,148.3	2,348.0	3,274.6	4,348.2	5,292.6	23,510.4
Latin America	330.0	96.4	301.5	510.5	405.6	583.8	450.8	585.3	3,263.8
Europe	650.4	241.3	396.8	453.5	552.0	329.8	563.4	561.5	3,748.7
Arab Countries	0.0	0.0	166.0	232.5	356.7	231.9	1,209.3	964.2	3,160.7
Global/Interreg	652.3	471.9	638.2	723.3	731.1	725.0	1,112.4	1,057.0	6,111.1
TOTAL	4,591.2	3,616.4	6,277.0	5,446.9	6,720.2	7,292.8	9,754.0	9,909.9	53,608.4
NUMBER OF PROJECTS	59	74	90	103	93	101	110	113	466
AVERAGE PER PROJECT	77.8	48.9	69.7	52.9	72.3	72.2	88.7	87.7	115.0

PERCENTAGE OF TOTAL TA

	1980	1981	1982	1983	1984	1985	1986	1987
Africa(sub-Sah)	1.7	1.7	1.8	1.8	2.6	2.3	2.0	1.4
Asia/Pacific	2.2	1.5	3.5	2.7	2.6	3.7	4.3	5.4
Latin America	0.4	0.1	0.3	0.6	0.5	0.7	0.4	0.6
Europe	0.9	0.2	0.5	0.6	0.7	0.3	0.6	0.6
Arab Countries	0.0	0.0	0.2	0.3	0.5	0.4	1.2	1.0
Global/Interreg	0.9	0.6	0.6	1.0	0.8	1.0	1.1	1.1
TOTAL %	6.1	4.1	6.9	7.0	7.7	8.4	9.6	10.1
TOTAL TA IN MILLIONS	$76.1	$88.5	$91.9	$78.0	$87.2	$94.5	$101.9	$97.7

PERCENTAGE SHARE OF REGIONS IN TOTAL ENERGY DISBURSEMENT

	1980	1981	1982	1983	1984	1985	1986	1987
Africa(sub-Sah)	29.0	41.4	25.7	25.3	34.6	27.7	21.0	14.5
Asia/Pacific	35.5	36.2	50.4	39.4	34.9	43.8	46.2	54.0
Latin America	7.2	2.7	4.8	9.4	6.0	7.6	5.0	6.0
Europe	14.2	6.7	6.3	8.3	8.2	4.2	5.7	6.0
Arab Countries	0.0	0.0	2.6	4.3	5.3	5.4	10.7	10.0
Global/Interreg	14.2	13.0	10.2	13.3	10.9	11.3	11.4	10.5
TOTAL	100	100	100	100	100	100	100	100

Annex 1
Source: Ref. No.32

STATISTICS TAKEN FROM UNIDO'S ENERGY INFORMATION SYSTEM (EIS)

HYDROPOWER DISBURSEMENT
US $ THOUSANDS

	1980	1981	1982	1983	1984	1985	1986	1987	TOTAL
Africa(sub-Sah)	0.000	0.000	220.000	199.000	141.000	785.000	200.000	92.000	1637.000
Asia/Pacific	0.000	172.000	151.000	241.000	159.000	139.000	309.000	257.000	1428.000
Latin America	47.000	37.000	0.000	32.000	50.000	0.000	0.000	0.000	166.000
Europe	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2.000	2.000
Arab Countries	0.000	0.000	0.000	0.000	0.000	0.000	143.000	23.000	166.000
Global/Interreg	187.000	43.000	0.000	36.000	33.000	35.000	66.000	243.000	643.000
TOTAL	234.000	252.000	371.000	508.000	383.000	959.000	718.000	617.000	4042.000

SOLAR ENERGY DISBURSEMENT
US$ THOUSANDS

	1980	1981	1982	1983	1984	1985	1986	1987	TOTAL
Africa(sub-Sah)	31.000	201.000	107.000	144.000	25.000	103.000	56.000	69.000	736.000
Asia/Pacific	3.000	40.000	1181.000	133.000	169.000	35.000	92.000	1134.000	2787.000
Latin America	5.000	36.000	8.000	15.000	13.000	22.000	27.000	50.000	176.000
Europe	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Arab Countries	0.000	0.000	0.000	169.000	49.000	0.000	32.000	56.000	306.000
Global/Interreg	0.000	0.000	19.000	97.000	0.000	0.000	10.000	0.000	126.000
TOTAL	39.000	277.000	1315.000	558.000	256.000	160.000	217.000	1309.000	4131.000

BIOENERGY DISBURSEMENT
US$ THOUSANDS

	1980	1981	1982	1983	1984	1985	1986	1987	TOTAL
Africa(sub-Sah)	67.000	138.000	55.000	23.000	20.000	220.000	79.000	37.000	639.000
Asia/Pacific	7.000	377.000	1295.000	652.000	764.000	1154.000	593.000	418.000	5260.000
Latin America	9.000	15.000	194.000	159.000	37.000	185.000	119.000	109.000	827.000
Europe	0.000	0.000	0.000	0.000	246.000	67.000	165.000	90.000	568.000
Arab Countries	8.000	4.000	70.000	6.000	35.000	34.000	63.000	156.000	376.000
Global/Interreg	131.000	85.000	132.000	23.000	215.000	137.000	341.000	29.000	1093.000
TOTAL	222.000	619.000	1746.000	863.000	1317.000	1797.000	1360.000	839.000	8763.000

WIND ENERGY DISBURSEMENT
US$ THOUSANDS

	1980	1981	1982	1983	1984	1985	1986	1987	TOTAL
Africa(sub-Sah)	35.000	16.000	15.000	0.000	0.000	0.000	0.000	21.000	87.000
Asia/Pacific	0.000	0.000	0.000	0.000	0.000	11.000	0.053	0.000	11.053
Latin America	0.000	0.000	0.000	0.000	0.000	0.000	0.000	71.000	71.000
Europe	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Arab Countries	0.000	0.000	0.000	0.000	0.000	0.000	0.000	8.000	8.000
Global/Interreg	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL	35.000	16.000	15.000	0.000	0.000	11.000	0.053	100.000	177.053

TOTAL NRSE DISBURSEMENT
by source

	1980	1981	1982	1983	1984	1985	1986	1987	TOTAL
HYDRO	234.000	252.000	371.000	508.000	383.000	959.000	718.000	617.000	4042.000
SOLAR	39.000	277.000	1315.000	558.000	256.000	160.000	217.000	1309.000	4131.000
BIO	222.000	619.000	1746.000	863.000	1317.000	1797.000	1360.000	839.000	8763.000
WIND	35.000	16.000	15.000	0.000	0.000	11.000	0.053	100.000	177.053
TOTAL NRSE	530.000	1164.000	3447.000	1929.000	1956.000	2927.000	2295.053	2865.000	17113.053
TOTAL ENERGY	4591.000	3616.000	6277.000	5447.000	6720.000	7293.000	9754.000	9910.000	

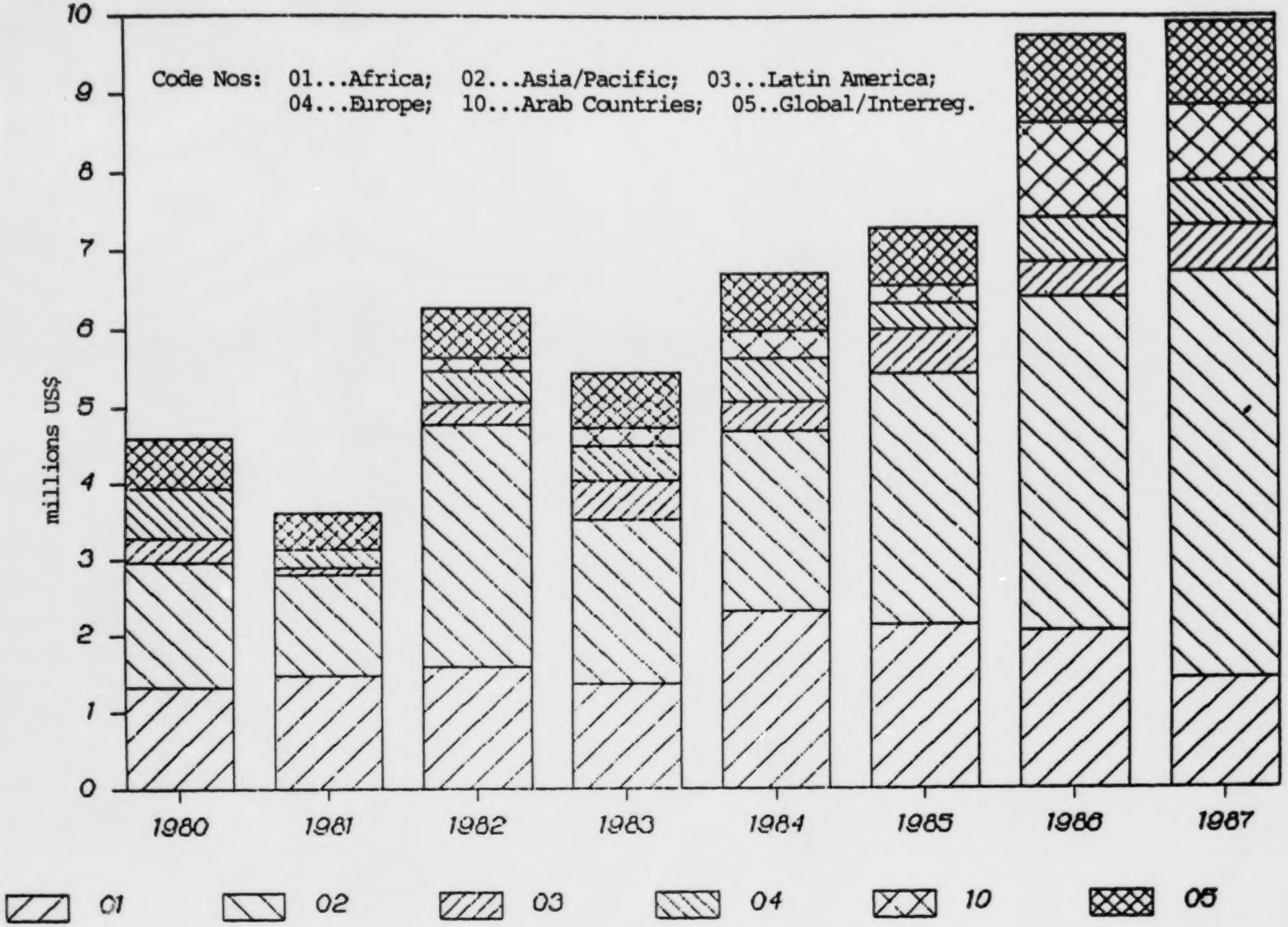
TOTAL NRSE DISBURSEMENT
by region

	HYDRO	SOLAR	BIO	WIND	TOTAL
Africa(sub-Sah)	1637.000	736.000	639.000	87.000	3099.000
Asia/Pacific	1428.000	2787.000	5260.000	11.053	9486.053
Latin America	166.000	176.000	827.000	71.000	1240.000
Europe	2.000	0.000	568.000	0.000	570.000
Arab Countries	166.000	306.000	376.000	8.000	[illegible]56.000
Global/Interreg	643.000	126.000	1093.000	0.000	1862.000

Annex 2
Source: Ref: No.32

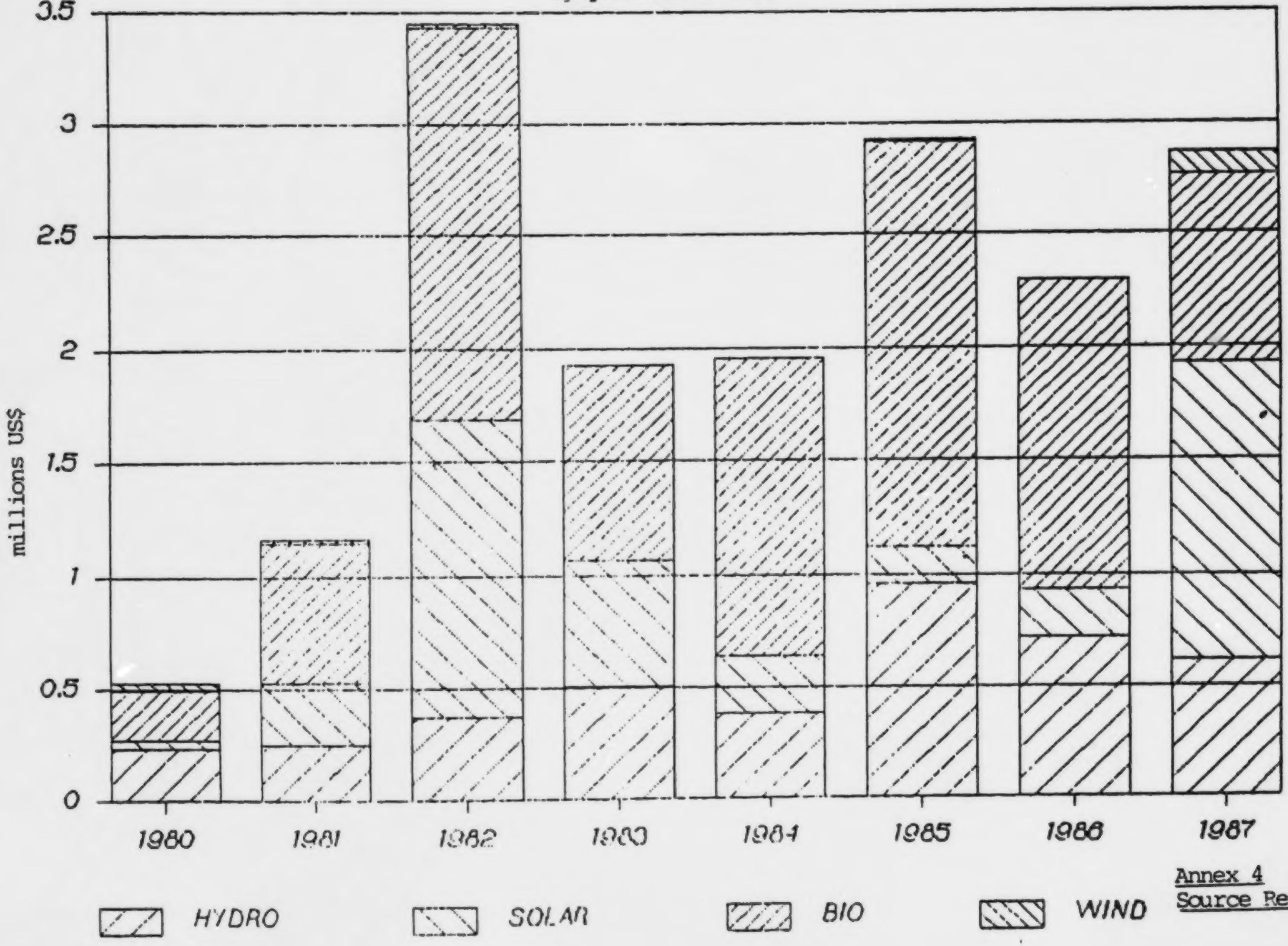
YEARLY REGIONAL DISBURSEMENT ON ENERGY

1980 – 1987



Annex 3
Source: Ref. No.32

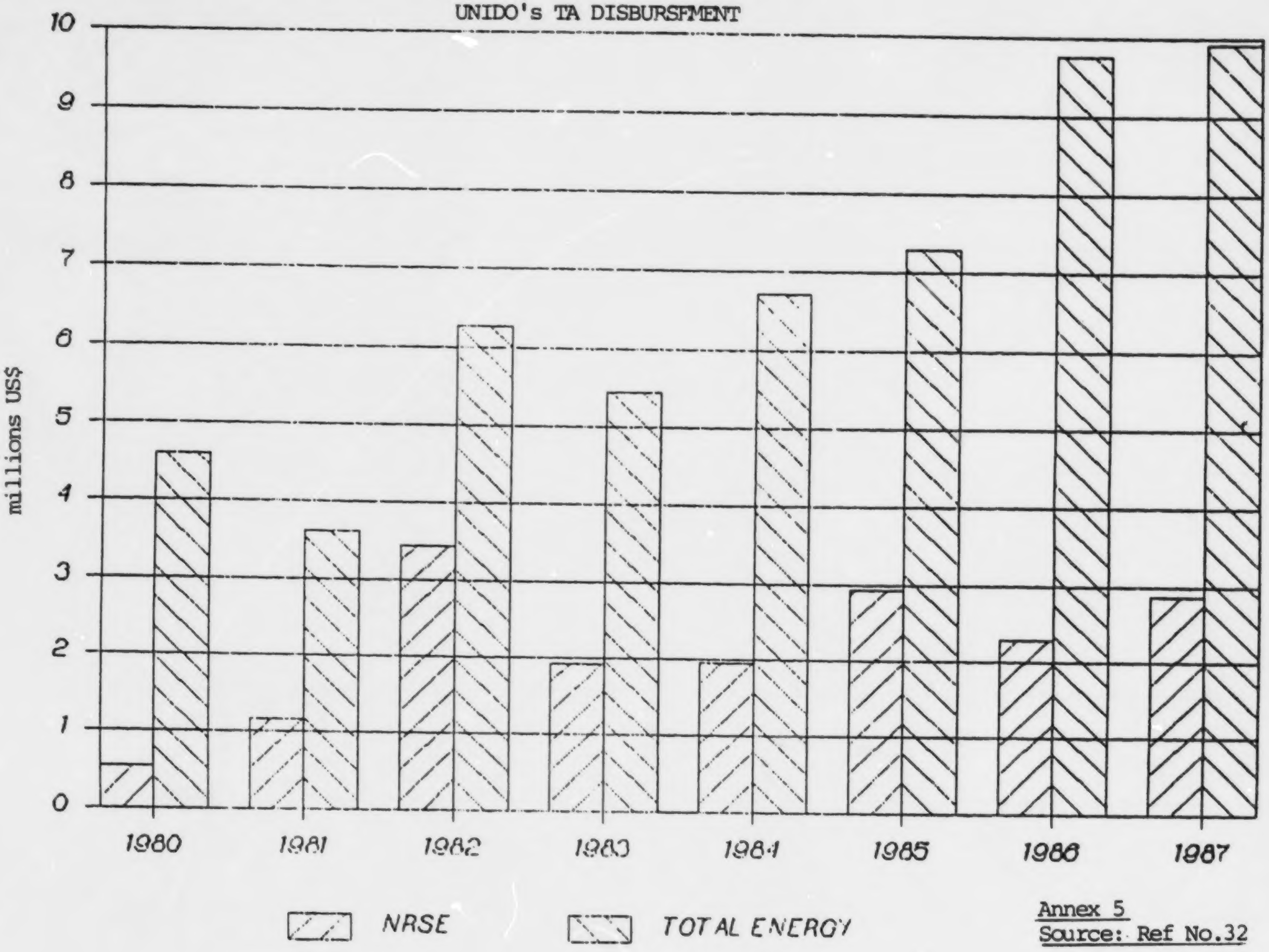
UNIDO's NRSE DISBURSEMENTS
by year and source



Annex 4
Source Ref: No.32

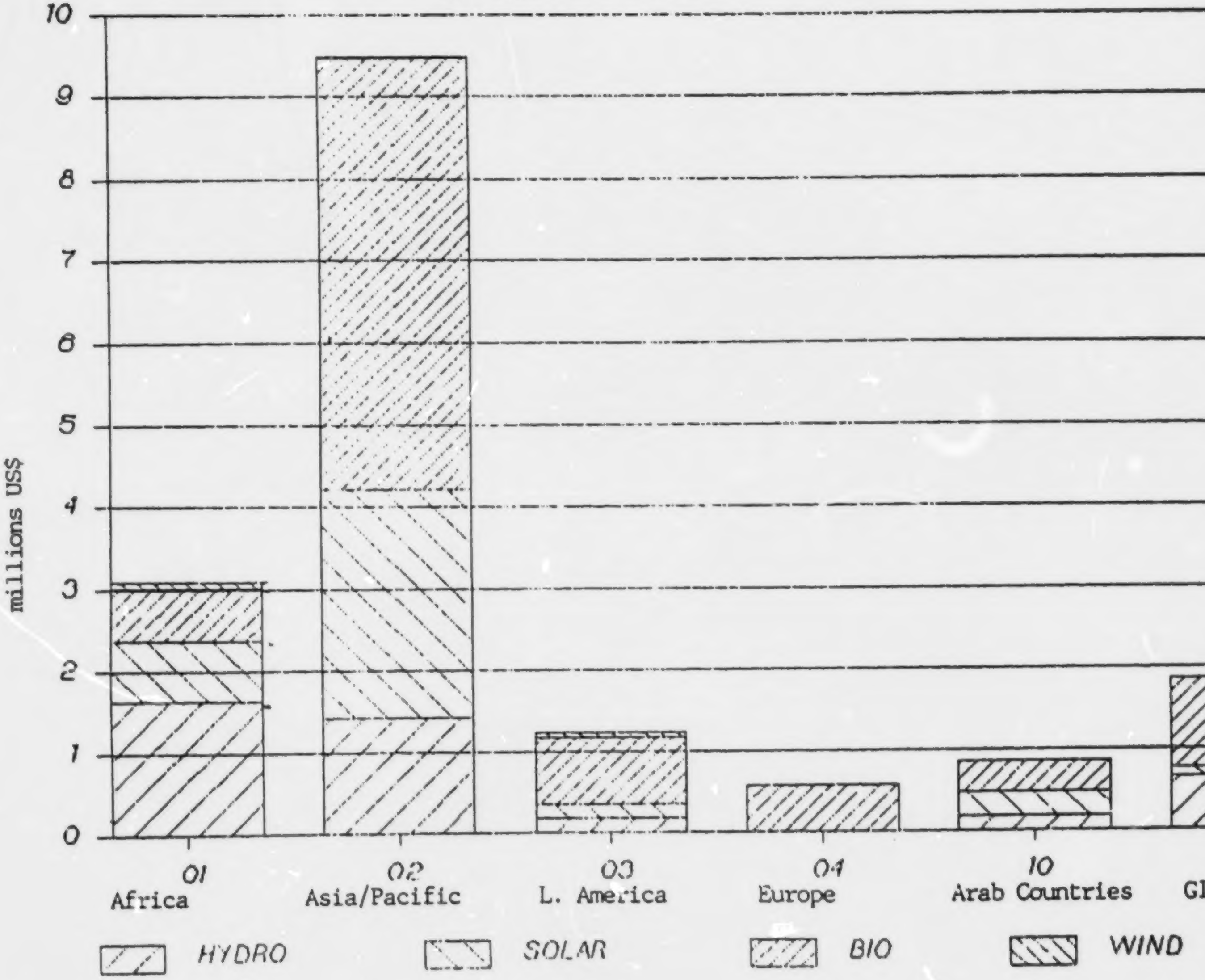
NRSE COMPARED WITH TOTAL ENERGY

UNIDO's TA DISBURSEMENT



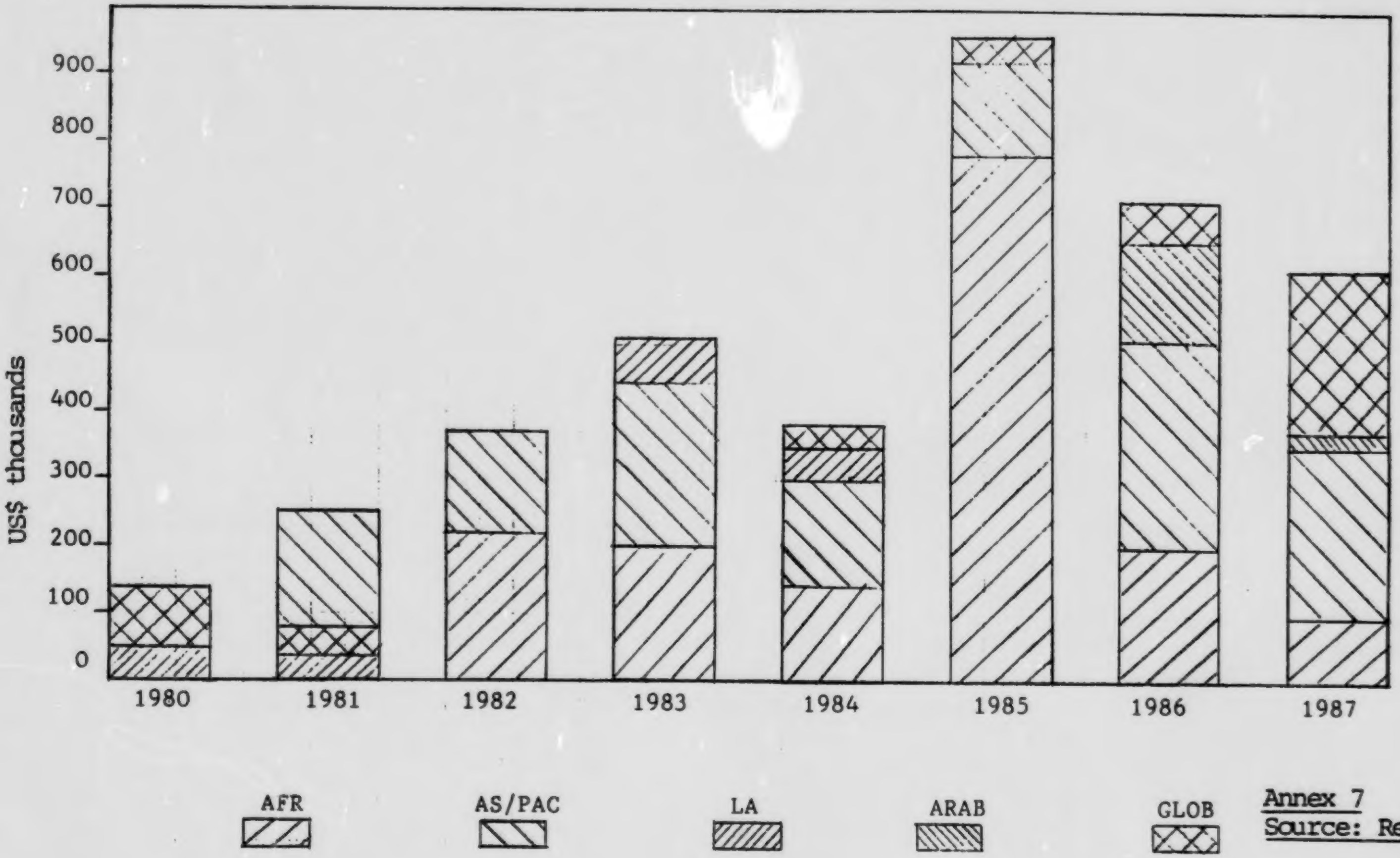
Annex 5
Source: Ref No.32

UNIDO's NRSE DISBURSEMENT
by region and source



Annex 6
Source: Ref No.32

UNIDO's Technical Co-operation programme on hydropower 1980-1987 - total expenditures; percentage share of regions.



Annex 7
Source: Ref. No.32

HOHA Hydro Power Plant
Main Characteristics

Hydrology	Catchment area		184	km^2
	Rainfall		1280	mm
	Average flows	Annual discharge	1.63	m^3/s
		Wet season flow	3.38	m^3/s
		Dry season flow	0.74	m^3/s
	Spillway design flood		30.0	m^3/s
Weir	Type	Fixed sill, masonry		
	Head	approx.	1.5	m
Intake	Type	Lateral, Diversion		
	Discharge		0.6	m^3/s
	Gate	Sliding gate (manual operation)		
	Features	Skimming wall, flushing channel		
Head-race	Type	Open channel, length	2.4	km
Canal	Cross-section	Trapezoidal, lined	0.88	m^2
	Gradient		1	per mill
Forebay	Type	Open bay, volume	2500	m^3
	Cross-section	Trapezoidal, lined		
	Features	Spillway, desilting pipe, intake structure		
Penstock	Type	Double steel pipe		
	Diameter x length		2 x 0.40 x 265	m
Power Plant	Installed capacity	Phase 1	300	kW
		Phase 2	350	kW
		Total	650	kW
Turbines	Type	Horizontal Francis		
	No. of Units		2	
	Gross Head		135	m
	Rated Speed		1500	RPM
Generators	Type	Horizontal	50	Hz
	Capacity	Phase 1	525	kVA
		Phase 2	475	kVA
	Power Factor		0.8	
	Voltage		400	V
Transformer	Type	Star-Delta		
	Frequency		50	Hz
	Rated Capacity	Phase 1	500	kVA
		Phase 2	1000	kVA
	Rated Voltage		0.4/15	kV
Transmission line	Type	Wood-poles		
	Voltage		15	kV
	Length	approx.	10.0	km

Annex 8
Source: Ref No.22

World Bank Experience in Minihydro - Malaysia and Indonesia

By
V.P. Thakor

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World Bank Experience with Minihydro in Malaysia and Indonesia

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ABSTRACT

The World Bank has been involved in the financing of minihydro developments in Malaysia and Indonesia. The underlying objectives of these operations were to promote economic development in remote rural areas endowed with hydro potential by providing electricity and to foster the development of indigenous capability for survey, evaluation, design and implementation of a continuing program of minihydro development.

The World Bank methodology for evaluating minihydro projects for eligibility for financing, consists of estimating the demand for electricity, identifying technical solutions for meeting the demand to establish the least cost option and calculating the internal economic rate of return on the proposed investments. A project is considered eligible for financing, if the economic rate of return equals or exceeds the opportunity cost of capital in the country. The paper discusses details of the methodology, and its application in the analysis of the selected projects. The paper also discusses measures required to make minihydro projects economically viable which include: (a) minimizing costs; and (b) maximizing the utilization of the plant output. Experience indicates that economically viable minihydro projects fall under one of the following categories: (a) those located in remote areas where the costs of alternatives are high; (b) those located in areas where demand has already been developed by the use of alternatives such as diesel generation, so that the full output of the minihydro plant can be utilized as soon as it is completed; (c) those which can be constructed at low cost because the necessary civil works have already been constructed for other purposes such as irrigation; and (d) those which can be constructed without extensive civil works and high-skill engineering and design input.

Introduction

1. Small hydroelectric plants have been used since the turn of this century to harness the energy of streams and rivers. The technology for the construction of such plants is the most mature and reliable among the technologies for the use of renewable resources. Small hydro plants have operated for forty to fifty years without much need for major maintenance or renovation. After some waning of interest in small hydro plants in the 1950's and 1960s due to the lower cost of alternatives using petroleum fuels, a revival was spurred by the increase in fuel prices in the 1970's. In the early 1980's, the small hydro plants appeared to be economically more attractive compared to diesel generating sets, for electricity supply in remote areas not served by central grids. It is during this period (1982) that the World Bank approved loans for the construction of minihydro plants in Malaysia and Indonesia. The paper describes the steps for the preparation of the projects, the methodology used for their evaluation for financing eligibility and the conditions under which the World Bank loans were made. An evaluation of the experience and the lessons learnt are then presented. The paper concludes that economic and financial viability of minihydro projects is difficult to achieve unless special circumstances exist.

Project Preparation

Malaysia

2. Its rugged topography and heavy rainfall makes Peninsular Malaysia particularly attractive for the development of minihydro schemes. In 1980, the Government of Malaysia appointed three consulting firms to investigate minihydro potential in the country. One firm was assigned the area of the Western Peninsular Malaysia, another the Eastern Peninsular Malaysia and the third was assigned the Sarawak and Sabah areas. The World Bank financed project was in the Eastern Peninsular Malaysia.

3. The consultants working in the Eastern Peninsular Malaysia identified 214 potential sites in the states of Kelantan, Trengganu, Pahang and Johor, on the basis of a desk study of topographical maps, hydrological data and other available information. Of these, 164 sites were considered viable for further study. Reconnaissance visits made to these sites showed that 115 sites were not suitable for development due to various reasons, such as difficulty of access, lack of market in the vicinity, excessive civil works cost, etc. Further detailed investigation resulted in the rejection of four more sites on technical grounds, leaving 45 sites which were evaluated in detail for plant size, layout, market, cost, benefit, etc. resulting in 41 sites, which appeared suitable for development.

4. The selected minihydro schemes were divided into three groups, viz: (a) those which would be connected to the grid immediately on commissioning; (b) those which were remote from the grid but would replace existing diesel generation; and (c) those which would serve isolated communities not likely to have supply from other sources in the near future. The justification for implementing schemes in the first category was based on their being able to provide energy at a lower cost than the long-run marginal cost of supply from the grid. The evaluation of the benefit from the second category of schemes was based on cost savings due to the displacement of diesel generation. For the third category, the justification was based on their being lower cost alternatives compared to diesel generation and on the quantification of the economic benefits arising out of the use of electricity by the consumers in the areas served by the schemes. The Bank loan was to be used to finance those schemes having an internal economic rate of return of at least 10%. The methodology for such an evaluation is discussed later in this paper.

5. Investigations showed that those schemes in the first category, i.e., those which could be connected to the grid, had comparatively high benefit/cost ratios since the plants could produce and deliver energy to the grid at high plant factors of operation, without being constrained by the patterns of demand, as would be the case for the schemes in the second and the third categories. It was also found that the grid in the Eastern Peninsular Malaysia would extend to most of the remote schemes by the end of the decade. Therefore, the design of the minihydro projects took into account the possibility of the grid-tie, permitting plant sizing to be optimized for maximum energy production from the available streams.

Indonesia

6. In 1981, the State Electricity Authority of Indonesia (PLN) commissioned a consulting engineering firm to investigate the minihydro potential in North Sumatra, as an alternative to diesel generation, for its electrification program in the region. In the first step, a desk study was carried out with 1:50,000 series topographical maps, for the western half of North Sumatra. The initial selection of the number of sites was limited by guidelines which required that the sites should be within 2 to 4 km from an existing road, within 10 km of an existing or planned 20 kV distribution line, and the catchment area should be between 10 and 300 sq km. More than 80 sites were identified which met these requirements.

7. The survey revealed that a number of sites had similar hydrological and topographical characteristics and could be developed using standard designs. The sites were therefore combined in groups with unit sizes varying from 75 kW to 1,500 kW, and operating heads of 10 to 50 meters. Forty of these sites were visited. At each site suitable locations for the weir, intake, aquaduct route and powerhouse were determined, and distances and elevations were noted down. Also, river condition, flow, topography, geology, vegetation cover of the catchment and environmental factors were noted. As a result of these investigations, 16 sites were considered suitable for further investigation.

8. Of the sixteen sites, ten sites had an operating head of about 15 m and were capable of being developed with a unit size of 750 kW. It was considered that in spite of some sacrifice in efficiency and optimal development, the standardization approach would yield a lower cost development option. It was, therefore, decided to follow the design standardization approach in further investigation. Detailed feasibility study of the ten sites, reduced their number to six which were selected for implementation. Four of these would have one unit of 750 kW and two would have two units of 750 kW each. These six minihydro projects were included in the World Bank loan for financing.

9. Standard designs were prepared for (a) weirs and river-bypass culvert; (b) diversion intake; (c) de-sand channel; (d) canal; (e) intake and penstock; (f) power house; (g) generating equipment; (h) switch-gear, protection and control; and (i) gates. The cost savings were expected mainly from the reduction in engineering, design and documentation; bulk purchase of identical electrical and mechanical equipment for all stations through one tender; and uniformity in spare parts and operator training. Also, the project objective was to prepare standard design manuals and train local engineering staff to enable them to apply the design concepts to future minihydro development, with small expenditure on engineering and design.

Methodology for Appraisal

10. The World Bank methodology for evaluating projects for eligibility for financing, which is applicable to minihydro projects, involves three steps. The first step consists of an analysis of the demand, i.e., the market for the electricity. The second step consists of the identification of the alternatives available for meeting the demand, evaluation of their cost and establishing the least-cost alternative for meeting the demand. Finally, the third step consists of evaluating the economic costs and benefits and calculating the internal economic rate of return on the proposed investment. A project is considered eligible for the World Bank financing if it is the least-cost option for meeting the demand and if the internal economic rate of return on the proposed investment is equal to or greater than the opportunity cost of capital in the country concerned.

11. The World Bank methodology differs considerably from that used by many consultants and utilities. A commonly encountered methodology in the feasibility studies for minihydro plants consists of determining the benefit/cost ratio of the project, taking into account the capital cost of the project, the financing cost and the value of energy produced by the plant at the unit cost of an alternative such as a diesel plant. A typical calculation is as shown below:

(i)	Plant Capital Cost for a 1,000 kW station	$2.0 million
(ii)	Capital Recovery Factor for financing at 8% p.a.	0.0888
(iii)	Annualized Investment Cost	$177,600
(iv)	Annual O&M	$ 20,000
(v)	Total Annual Cost	$197,600
(vi)	Energy Generation from the Plant	5.0 GWh
(vii)	Cost of Diesel Generation	7.2 cents/kWh
(viii)	Value of Minihydro Energy ($0.72 \times 5.0 \times 10^6$)	$360,000
(ix)	Benefit/Cost Ratio (viii ÷ v)	1.82

12. The above method ignores several important considerations. The most significant implied assumption in the analysis is that all the energy produced by the minihydro plant will be consumed as soon as the plant is commissioned. It also assumes that the production pattern of the minihydro plant (especially for a run-of-the-river type) would be the same as the pattern of the demand. It further assumes that the capital expenditure profile for the construction of a minihydro plant will be the same as that for a diesel plant. In a real situation, the development with diesel generators could be phased to suit the growth of the demand, whereas the investment for the minihydro plant has to take place at the front end of the development, which results in different net present values of the investment costs. Finally, the analysis assumes that the interest rate on borrowing equals the opportunity cost of the capital in the country, which is often not the case in a developing country where the project may be financed by concessionary loans or credits.

13. The benefit/cost ratio for the above case using the distributed costs and discounted values of costs, is worked out in the following table (Table 1). The 1,000 kW minihydro plant is compared to an alternative using 1,200 kW (4 x 300 kW) diesel generators, costing $700 per kW and having a fuel cost of US¢4.5 per kWh; giving the average cost of about US¢7.2 per kWh. It is assumed that the full energy utilization of 5 GWh p.a. will take place in the fourth year after the commissioning of the mini-hydro plant. The diesel installation is suitably phased to meet the demand growth. A discount rate of 8% is used. The revised calculations show that the benefit/cost ratio will be 1.26 instead of 1.82 obtained by the previous calculations. It may be noted that in both these calculations, it is assumed that all the energy that can be produced by the mini-hydro plant will be consumed, implying that the pattern of demand will suit the pattern of production, which is rarely the case in a run-of-the-river mini-hydro plant supplying an isolated area. If the full utilization of the energy produced by the mini-hydro plant were not to take place for many years (say, five or seven years) after its commissioning, the diesel alternative could prove to be a lower cost solution.

Table 1: CALCULATION OF THE BENEFIT/COST RATIO
USING DISCOUNTED CASH FLOW METHOD
($ million)

Year	Minihydro Capital Cost	Minihydro O&M	Minihydro Total	Diesel Generation Capital Cost	Diesel Generation O&M	Diesel Generation Fuel	Diesel Generation Total
1	0.5	-	0.5	-	-	-	
2	1.0	-	1.0	-	-	-	
3	0.5	-	0.5	0.21	-	-	0.210
4	-	0.02	0.02	0.21	0.015	0.054	0.279
5	-	0.02	0.02	0.21	0.030	0.108	0.348
6	-	0.02	0.02	0.21	0.045	0.162	0.417
7	-	0.02	0.02	-	0.060	0.225	0.285
8-20	-	0.02	0.02	-	0.060	0.225	0.285
Discounted value of costs			1.97				2.49

Benefit/Cost Ratio = 2.49 ÷ 1.97 = 1.26

14. This discussion brings out several important areas which need to be carefully explored prior to the implementation of the minihydro projects in order to ensure their financial and economic viability. The most important area is the need for a careful analysis of the market. The demand for electricity and the pattern of consumption in the service area of the minihydro plant have to be forecast with reasonable accuracy. Since the capital cost of a minihydro plant is generally higher than the diesel alternative, and since all the cost is incurred upfront, ensuring that a market would exist for the energy that can be generated by the plant is of crucial importance to the viability of the project.

Market Analysis

15. Three types of market situations are generally encountered. One, the isolated market where there is no electricity supply prior to the construction of the minihydro plant but where potential demand exists. In most cases such a market will be in remote rural areas, consisting of demand from households, shops, irrigation, fishing, and agro-based or cottage industries. Demand forecasting for such a market is generally difficult and uncertain. Also, the pattern of consumption is most likely to be at a low load factor, the peak demand primarily occurring due to the lighting loads in the evening hours. In such situations, justification for the construction of minihydro plants is likely to be difficult. In Malaysia, the Government's intention in initiating the minihydro program was to use them to electrify remote rural areas where the grid supply was not expected to reach for many years. However, detailed

studies showed that none of the project proposals for such areas were financially or economically justifiable largely because the forecast pattern of consumption would have led to a relatively low utilization factor for the generating capacity in the initial years. Special circumstances would have to exist to make such projects viable, which would include areas where the cost of diesel generation would be very high due to transportation or access difficulties (e.g., Irian Jaya in Indonesia) or where minihydro projects can be implemented at low cost, say, due to the availability of most of the required civil works in an existing irrigation scheme.

16. The second type of the market is where the minihydro plants would substitute for diesel generation, either fully or partially. In such situations, some electricity demand already exists and their pattern is known. The North Sumatra minihydro development in Indonesia fell into this category. In such situations the pattern of demand, i.e., the load curve, becomes important. In the North Sumatra project where the minihydro projects have been commissioned recently, the peak demand has developed sufficiently to absorb the full output of the minihydro plants but such demand lasts for only three or four hours in the evening. The day time demand has not developed, leaving a considerable amount of unutilized hydro energy. If the demand does not develop rapidly, the minihydro schemes will have a much lower economic rate of return than that estimated at the time of the appraisal. A great deal of attention and effort would be necessary to develop the productive uses of electricity (i.e. day time loads) by complementary rural development projects which provide other inputs necessary for economic development. These would include rural roads, credit for investments, vocational training, etc. This load promotion aspect is often ignored while implementing minihydro projects.

17. The third type of market is where the minihydro project is located close to the grid or a large market, so that all the energy produced by the plant is used. In many situations, it is justifiable to incur the additional cost of constructing transmission or distribution lines from the minihydro plant to the grid 15 or 20 km away, to capture the additional benefit of the absorption of the surplus energy by the grid. The grid connection also helps in sizing the capacity of the minihydro plant to utilize the energy potential of the river flow to the maximum extent. It should however be mentioned that the value of energy from the minihydro plant, when connected to the grid, would be equal to the avoided cost of the grid which may be considerably lower than the diesel substitution cost. Nonetheless, in the Malaysia project, several minihydro projects became economically justifiable when the investment for the grid connection was included and the plant capacity was optimized for the supply of energy to the grid.

Capital Cost

18. The importance of reducing the capital cost of the minihydro projects is obvious for their economic and financial viability. A large body of technical literature exists on the cost reduction measures, and it is beyond the scope of this paper to discuss these measures. A great deal of attention was paid to this aspect in the Malaysia and Indonesia minihydro projects. In Malaysia, the National Electricity Board (NEB) began to develop several pilot minihydro sites in 1980, each incorporating different design and equipment features. Eight such projects were completed by the end of 1983. NEB had

also set up a minihydro department to plan, design and implement future schemes, taking into account the optimal features of the pilot schemes. In Indonesia, the project was meant to be a pilot to demonstrate the benefit of standardization, and develop appropriate manuals and guidelines for continuing investigation and development of other minihydro resources for the whole country. Training of the local staff to perform these tasks was an essential element of the project.

19. The completion cost of the six minihydro plants[a] in North Sumatra with a total capacity of 6000 kW are shown in Table 2.

Table 2: COMPLETION COST OF SIX MINIHYDRO SCHEMES

Item	Foreign US$ x 10^3	Local Rp million	Total Equivalent US$ x 10^3
Feasibility studies and Design	516	307	954
Civil Works	-	5,457	4,443
Electrical & Mechanical Equipment & Installation	3,753	300	3,971
Construction Supervision, Project Management and Engineering Services	1,776	1,580	3,191
Total	6,045	7,644	12,559

The total cost worked out to US$2,093 per kW, which was within the estimated budget. The cost of civil works, electrical and mechanical equipment and installation was $1,396 per kW, which were substantially lower than the budget. The engineering, designs and construction supervision cost worked out to $697 per kW which was significantly higher than the estimates. This is partly explained by the fact that the engineering services included the preparation of minihydro resource manual, carrying out of feasibility studies for four additional schemes and training. Large costs were incurred in construction supervision due to the unsatisfactory performance of the local contractors entrusted to carryout the civil works. The costs do not include the investment in the transmission lines needed to deliver electricity to the load centres.

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a/ The six minihydro plants are: Kombih 1, Kombih 2, Silang, Raisan 1, Raison 2 and Sibundong in Western North Sumatra.

20. In Eastern Malaysia seven minihydro projects which are currently under implementation, range in size from 220 kW to 630 kW, with a total capacity of 2,785 kW.[b] The estimated cost to completion for these projects is approximately as follows:

	US $ million
Civil Works:	2.6
E&M Equipment:	1.3
Transmission Lines:	1.0
Indirect Costs:	0.8
Contingencies:	1.0
Total	6.7

21. The total cost will be about $2,500 per kW including $359 per kW for transmission lines which are constructed to permit the interconnection of the stations to the grid, to improve the energy utilization. The cost of civil works and the electrical and mechanical equipment in these projects will also be about $1400 per kW, as in the Indonesian project. The indirect costs, which include the engineering and the construction supervision, will be lower in the Malaysian project because they exclude the cost of the feasibility study carried out by expatriate engineers and because the subsequent follow up work is being carried out by NEB's own staff.

Economic Evaluation

22. As mentioned in para. 10, the third step in the establishment of the project justification is the calculation of the internal economic rate of return (IERR) for the project. The IERR is defined as the discount rate at which the net present value (NPV) of the project is zero. In these calculations, economic costs of the project and economic benefits arising out of the supply of electricity are used. The concept of "shadow pricing" (prices that would prevail if all goods were traded freely in "perfect" markets) is used for both costs and benefits. The primary implication of this approach on the cost side is that prices of equipment and materials are net of taxes and subsidies. In addition, labor costs are adjusted to reflect the shortage or surplus of the class of labor concerned. The shadow price for the land can be neglected in the analysis if it can be assumed that the land would be restored to its previous use following the useful life of the plant.

23. Consumer welfare (as reflected in the consumers' willingness to pay) is used as a basis for the valuation of the benefits, rather than the revenue from the sale of electricity. It is generally accepted that the provision of electricity results in several benefits not captured by the selling rate. These include (a) substitution of kerosene for lighting; (b) better quality of lighting than that available without electricity; (c) extension of working hours in the evenings; (d) use of domestic appliances such as television, electric irons, rice cookers, and fans which improve the quality of life; and (e) potential employment arising out of the productive uses of electricity in

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b/ The seven minihydro plants are: Keshar and Pertang in Pahang; Cheralak and La in Trengganu; and Sok, Lata Tunggil and Keneroh in Kelatan.

cottage and agro-industries, irrigation, water pumping, ice making, cold storage, etc. It is often difficult to quantify the value of all these benefits in monetary terms. However, an attempt is made through surveys to measure the consumers' willingness to pay and this is used for the valuation of benefits.

24. In the appraisal of the Malaysia project an attempt was made to quantify the benefits for domestic, commercial and industrial consumers for the purpose of the economic evaluation. For the domestic consumers, an estimate was made of the saving in the kerosene cost for lighting purposes, as set out in Table 3, which amounted to M$ 7.78 (US$ 3.38) per household, per month, in rural areas. The total economic benefit from the sale of electricity to domestic consumers was assumed equal to the revenue at the prevailing tariff plus the savings due to the substitution of kerosene.

Table 3: SAVINGS DUE TO ELECTRICITY FOR LIGHTING

Electricity	Monthly Cost M$	Kerosene	Monthly Cost M$
1. Wiring cost @ M$ 200 annualized over ten years @ 10%	2.71	1. One petromax lamp @ M$ 45.0 annualized over 10 years at 10%	0.61
2. At M$ 1.0 per bulb and a life of 1000 hrs.	0.12	2. Fuel cost for 8 kWh equivalent of kerosene @ M$ 1.45 per kWh	11.60
3. Electricity cost @ 20 M cents per kWh for 8 kWh per month	1.60		
Total	M$ 4.43	Total	M$ 12.21

Cost saving = M$ 7.78 per month per household
(US $1.0 = M $ 2.30)

25. For industrial consumers, the willingness to pay (or the benefit) was equated with the cost of alternative method of generating electricity by diesel sets. This was considered a reasonable assumption since industrial consumers would produce electricity by inhouse generators, in case the supply from the public utility was not available. For commercial consumers such as shops and restaurants (coffee shops), who constituted a large percentage of such consumers in rural areas, a survey indicated, that the weighted average of surplus benefit ranged from 55% to more than 100% of the direct benefit, viz. revenue from the sale of electricity. Combining the results of these studies, the total benefit due to sale of electricity to the estimated group of domestic, commercial and industrial consumers worked out to about M¢ 37 per kWh (US ¢16.0) compared to the average revenue to NEB of about M¢ 22 per kWh (US ¢ 9.6). The application of the methodology described here was used to evaluate the 41 sites which were selected. It showed that only 14 sites met the World Bank criterion of having IERR greater than 10%.

Recent Development

26. The appraisal of the minihydro projects in Malaysia and Indonesia took place in 1981/82. In the period from 1984 to 1986, however, a considerable decline in the oil prices took place. Therefore, the cost of the minihydro plants which appeared attractive in the high oil price era, is no longer so now. This provides all the more reason to look at the minihydro projects more carefully in the current price environment and devise methods for cost reduction and better utilization of the energy output. Since the decline in the oil prices took place prior to the finalization of contracts in Malaysia, NEB and the Government of Malaysia reviewed the justification of the program with the World Bank and decided to implement only seven economically attractive schemes in the Eastern region. Thus the use of the economic evaluation criterion incorporated in the World Bank loan, prevented investment which would have, otherwise, turned out to be uneconomic.

Conclusions

27. From the discussions of the two projects, included in this paper, it is clear that measures required to make minihydro projects economically and financially viable include: (a) minimizing their capital costs; and (b) maximizing the utilization of the plant output as early as possible after its commissioning. Low cost minihydro plants would be possible in situations where the necessary civil works have already been constructed for other purposes such as irrigation or in situations where relatively simple construction is possible without the use of high engineering and design skill. The capital cost that can be justified for such projects is a function of the characteristics of the demand for electricity that would exist in the area of supply. Economic viability of the minihydro projects can be significantly enhanced if the electricity demand has already been developed by the use of alternatives such as diesel generation or if the full potential of the energy production is absorbed in a grid. Minihydro plants do not appear to be the least cost option for developing electricity supply in isolated rural areas where the growth in the electricity demand takes place over many years.

28. Special circumstances may exist which may justify some modification of the methodology for evaluating minihydro projects in some developing countries. For example, in a project in Laos, minihydro appeared preferable to diesel generation on account of the difficulty in procuring diesel in remote areas, and due to a scarcity of operation and maintenance skills which made it impossible to maintain the diesel sets in proper operating condition. Also in some countries, it is more difficult to obtain the funds to procure fuel and spare parts needed for operation and maintenance of diesel sets, than to obtain capital funds for the construction of new projects. In such cases, minihydro schemes may have some advantage.

29. In conclusion, the economic and financial viability of minihydro projects appears difficult to achieve unless special circumstances exist. Also, the World Bank experience indicates a need for carrying out a case by case study of each minihydro scheme.

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Washington, D.C., U.S.A.

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Hydroelectric Project Appraisal: Profession, Science and Art

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HYDROELECTRIC PROJECT APPRAISAL:

PROFESSION, SCIENCE, AND ART

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With the resurgence of interest in hydroelectric power development during the last decade, there has emerged also a demand for competent and professional hydroelectric project appraisal skills. While the preparation of a professional appraisal is usually required by lenders as a condition of project financing or refinancing, the requirement for professional appraisal skills extends well beyond this circumstance. Such skills are also needed to determine and justify offering prices for developed or undeveloped sites available for purchase, of additional real property and/or water rights which may be required to complete a project development, and of shares in project partnerships or corporations which are being dissolved or bought out pursuant to previous agreements. Insurance claims by hydro project owners also require objective, third party determination of the value of a part or all of a project.

Although a real estate appraisal profession already does exist in the United States and internationally, few appraisal professionals possess the specialized knowledge of hydropower technology or of the electric power business to prepare competent appraisal reports on hydropower sites. On the other hand, engineering professionals who have special skills in hydropower technology usually do not possess the appraisal skills necessary to complete a value determination.

Identifying persons with the necessary skills to prepare competent hydroelectric appraisals is made even more difficult by the rapid pace of change in the electric power business. In the U. S. A., three examples of such change seem particularly noteworthy for the appraisal profession.

First, the rapid growth of an independent power production industry which competes for market share with traditional electric utilities (largely outside of the purview of government regulation) has limited the applicability of the conventional regulatory principle of "depreciated original cost" when valuing electric plant in service. Second, many utilities have faced increasing competition from independent power producers by creating special subsidiaries which are themselves "independent power producers", not charged with the legal obligation to provide "public service" and thus exempt from the "orignial cost" principle. Third, although the enactment in 1986 of the Electric Consumer Protection Act (PL 99-495) appears to have settled the issue of municipal preference in hydroelectric relicensing, the question of the appraised value of hydroelectric stations lost to an independent power producer in a competetive relicensing procedure appears to be an open one.

Given this context of rapid change and its associated uncertainty, the purpose of this paper is to assist the industry by providing guidelines on how to identify competent appraisal professionals and by highlighting the particular errors to which appraisers, uninitiated in the pitfalls of the hydropower industry, may fall prey. Along the way, it will also address a number of challenges to the apraisal profession brought on by the current tide of change in the electric power generation business.

THE APPRAISAL PROFESSION

Like the electric power business, the appraisal business is also in a state of significant change. Prior to 1986, no state in the U. S. A. required licensing of real estate appraisers or established standards for competent appraisal reports; although, as a practical matter, the creation of Fanny Mae and Ginny Mae mortgages imposed some uniformity on appraisal reports with respect to homes.

In September 1986, Congressional investigations into a flood of suspicious bank failures (many of which involved trumped up appraisal reports on mortgaged properties) resulted in the preparation of Uniform Standards of Professional Appraisal Practice, a Congressional recommendation that the individual states monitor the licensing of appraisers, and a request that federal financial regulators be given the authority to discipline appraisers guilty of willful negligence or the deliberate misrepresentation of value. Since then, no relevant federal legislation has passed, although a few states have enacted laws regulating the appraisal profession in some small way. Thus, for example, the state of Louisianna enacted legislation, in September 1987, calling for the voluntary certification of appraisers; and the states of Michigan and Florida now require appraisers to pass their standard real estate salesperson licensing exams (although no special training or testing is offered for appraisers). Only the states of California and Nebraska have enacted laws requiring that appraisals meet minimum standards of professional competence.

Beyond this limited government regulation, standards for professional appraisals and relevant training in the profession have been, and continue to be, provided by private trade associations. Although many such associations exist in the United States, the two best known professional appraisers' associations are the American Institute of Real Estate Appraisers (AIREA) and the Society of Real Estate Appraisers. Both groups are headquartered in Chicago, have state-based chapters throughout the nation, are international in scope, offer training and testing for would be appraisers, have established codes of ethics for the appraisal profession, and provide varying levels of certification to practicing appraisers (depending upon their degree of training and experience). Both associations are looked to for help and information in the various attempts by government to establish tighter controls on the profession.

However, until the time when appraisers are subject to public licensing requirements, the only proxy for measuring the competence of appraisers is the designation system of the two appraisers' trade associations (see Figure I, below). These designations may be helpful for identifying appraisers who, by virtue of their exclusively residential orientation, appear to be unqualified for the complications of a hydroelectric appraisal. However, given the relatively recent development of these certification systems and the special knowledge required to conduct a hydroelectric project appraisal, the key criteria for identifying qualified appraisers will necessarily remain the recommendations of that appraiser's previous clients and the client's best judgement of relevant appraisal skills.

In an effort to refine the ability of the hydroelectric industry to make such judgements, the following section identifies the standard techniques of real estate appraisal as they might be applied to the valuation of an operating or proposed hydroelectric station.

FIGURE I

PROEFSSIONAL DESIGNATIONS OFFERED BY THE TWO LEADING
REAL ESTATE APPRAISAL ASSOCIATIONS IN THE U. S. A.

AIREA	Soc. of R. E. App.
1. RM (Residential Member, primarily oriented toward residential appraising)	1. SRA (Senior Residential Appraiser, primarily orientend toward residential appraising)
2. MAI (Member, Appraisal Institute, highest designation, requires some commercial property experience)	2. SRPA (Senior Real Property Appraiser, requires some commercial property experience)
	3. SREA (Senior Real Estate Analyst, highest designation, requires long and varied experience)

THE SCIENCE AND ART OF APPRAISAL

"An appraisal is an unbiased estimate of the nature, quality, value or utility of an interest in, or aspect of, identified real estate." (1) The preparation of such estimates, and the certification of their validity, is the major function of the appraisal professional.

Three standard techniques comprise the science of real estate appraisal: sales comparison, income capitalization, and the cost approach. The art of appraisal is applied in determining which of the three approaches is most appropriate to the property being valued and, where all three are used, in weighing the results of each for purposes of reconciling the different value indications which may result from the different techniques. Although the sales comparison approach involves explicit comparison of the subject property to other like properties, it will be seen that all appraisal techniques involve some form of comparison.

(1) The Sales Comparison Approach

This approach bases the market value of a property on the price which others have paid for similar properties. To be reliable, this approach requires a relatively long list of "comparables" as well as very close attention to the different sales environments and conditions of sale which may have influenced the price paid for the comparison sites. Since two properties are seldom exactly alike, the appraiser's task is to control for the influence on value attributable to such differences. Given a sufficiently large number of comparables, any of the variables examined by the appraiser may be subject to linear or multiple regression in order to determine the degree of their likely influence on the appraised value of the subject property.

Irrespective of the type of property being appraised, the sales comparison approach requires answers, at the very least, to the following general questions about each of the comparable sales: Was the sale an arms length transaction? Were price concessions made to achieve a quick sale? Did the seller offer below market financing to the buyer? What changes in market condition may have occurred since the comparable properties were sold? What physical amenities are present in some of the comparables and not others? Which are present in the subject property? How do market forces vary across the different geographical areas in which the comparable properties are located?

(2) The Income Capitalization Approach

Under the income capitalization approach, the net operating income from a property is converted to a cash value by use of a posited or derived overall capitalization rate. Thus, on a property with a net one year operating income of $1,000,000, a posited capitalization rate of 12.5% would produce a capitalized value for the subject property of $8,000,000. (Value = net operating income / overall capitalization rate). Obviously, the capitalization rate selected will have a major influence over the determined value, and particularly if it is derived by the appraiser, it must be defensible. Derivation of capitalization rates is typically accomplished by examining the capitalization rates of comparable sales, but may involve comparisons with respect to a number of other income-related variables.

Although useful for some purposes, direct capitalization has the disadvantage that it only looks at the first year of income to a property. Assumptions and forecasts about holding period, future income streams, and future improvements are not examined. Given that hydroelectric stations are typically looked upon as very long-term investments, we believe that simple yield capitalization is not an effective way to appraise the value of hydroelectric investments, and prefer the subset of income capitalization techniques known as "yield capitalization".

Yield capitalization posits the value of an income producing property as being the sum of the present values of the stream of annual net revenues resulting from the project over a distinct period of time (i.e., net present value), including the sale (or reversion) value of the property at the end of the holding period, discounted at an aceptable rate of return on investment (or yield rate). Typically, this "acceptable" rate of return on investment is a derived value based on the typical yield anticipated by other (comparable) investors in the same or similar markets.

Obviously, there are two keys to the appraised value which will be calculated by the yield capitalization technique: the projection of annual gross and net income and the selected yield rate, and it is incumbent upon the appraiser to pay special attention to guaranteeing the validity of these values.

(3) The Cost Approach

This approach to value is based on the recognition that the value of a property reflects market perceptions as to the cost of building a similar project new. On an existing improved property, the appraiser will first determine the current cost of replacement of any relevant improvements and then deduct from that figure the accrued depreciation inherent in the subject property. Such depreciation is understood to result from physical deterioration, functional obsolescence (the negative effect on value resulting from original design defects), and external obsolescence (the negative effect on value atrributable to influences from outside of the site). In theory, the difference between the market value and the replacement cost of a property is always equal in value to accrued depreciation.

On an unimproved property, the cost appraoch is particularly useful in determining the value of land alone or partially improved land not capable of achieving its full utility. That is, the value of the land alone will be equal to the value of the property after it is improved, less the cost of the improvements required to complete the improvements. Regardless of whether the subject property is improved or unimproved, the cost approach also involves comparison, both in determining the cost incurred to improve other properties and in measuring the contribution to utility which may be derived from the land alone.

THE APPRAISAL OF HYDROELECTRIC PROJECTS

While the three approaches to appraisal outlined above are fairly straightforward and self-explanatory, each of them require substantial research by the appraiser in order to derive a defensible value. When applied to hydroelectric projects, the specific questions which need to be addressed are not obvious to appraisers uneducated in hydroelectric technology and/or the economics of the electric power business. The purpose of the following section is to identify, with respect to each appraisal approach, the specific questions which need to be addressed in order to complete a hydroelectric appraisal.

Common to all three approaches is an inquiry, at the outset, as to the legal permissibility of the subject project. In the U. S. A., this means that the appraiser must, at the very least, be knowledgable about the hydroelectric licensing process as well as about the regulatory procedures of the particular state in which the project is located. With respect to the latter, it is clear that there is some similarity across all the states in the way in which hydroelectric project development and operation are regulated. Nevertheless, it is important to be alert to differences among the states insofar as different regulatory environments affect the perceived value of a project.

On properties proposed to be acquired for the future development of hydroelectric potential, the appraiser must inquire as to the likelihood of acquiring a license; measure the probability, source and degree of opposition to the proposed project; identify the types of license conditions which may be imposed and their impact on project cost and income; and estimate the cost which will be incurred in acquiring the license.

On hydroelectric stations which are already in operation or sufficiently developed to qualify for financing, we assume that, by definition, a FERC license or exemption from licensing has been granted* and that the license conditions are easily identifiable. In this scenario, the appraiser must be able to measure the impact of these conditions on project cost and income and, in instances where a licensed site is being purchased, measure the market value of the license itself (typically, though not always, the foregone expense to the buyer of acquiring the license himself). In addition, the appraiser must weigh the security of the market for power to be generated by the project. Numerous questions suggest themselves in this vein: (1) Is their a long term power purchase contract and what are its terms? (2) What is the impact on value of this contract? (3) Who is the purchaser? (4) How reliable is the purchaser? (5) What is the impact on project value of an unreliable purchaser? (6) In instances where the power to be generated will be used on site, what is the value of this power now and in the future, and with what degree of confidence can we predict future electricity prices?

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* In the U. S. A. there are a number of operating hydroelectric stations which are either grandfathered under the Federal Power Act and therefore unlicensed or nearing the end of the term of their license. Depending upon the buyer's intentions, this fact may influence significantly the station's market value.

While each of these questions may be more or less significant to the particular appraisal approach selected and may be of greater or lesser significance depending on the purpose of the appraisal, they are sufficiently significant in their own right that they must be viewed as a preface to almost any hydroelectric project appraisal. Therefore, in examining below the applicability of each of the three approaches to hydroelectric sites, we will not repeat these questions.

(a) The Sales Comparison Approach

In general, we would argue that the sales comparison aproach, taken alone, is never adequate to appraise the value of a hydroelectric station. This is based on the conventional wisdom that no two hydroelectric stations are precisely alike. Indeed, it is a fairly recent phenomenon, at least in the U. S. A., that turbine-generators are not fully customized to sites. Given the noncomparability of most sites, there are so many variables to be controlled that an accurate sales comparison would be exceedingly complex. Such variables as power market, environmental consciousness, regulatory approach, labor markets, competetiveness of other water resources, dam safety, insurance costs, and even project design will vary regionally and must be taken into consideration by the appraiser. Add to this the general questions asked earlier about conditions of sale, time of sale, and financing conditions and the appraiser's task under the sales comparison approach becomes too complex and judgement begins to replace science in the value determination.

A second reason why the sales comparison approach used alone can not provide a defensible hydroelectric value determination is that information on other hydroelectric site transactions is often confidential and not readily available for comparisons. It is true that prospectuses, annual reports, and K-1 forms of public corporations as well as registries of deeds can provide some information on project acquisition costs, they fail to provide answers to the numerous questions which need to be addressed in order adequately to complete a comparison.

Where information is available however, the sales comparison approach can be a useful supplement to the other techniques of appraisal, although we suspect that its results will usually be heavily discounted in any reconciliation and final value determination. When it is used we would advise the client to be alert to the final unit of comparison utilized by the appraiser.

A common rule of thumb applied by independent hydroelectric developers is a dollar cost per kilowatt or megawatt of installed capacity, and there might be a built in propensity to accept this unit of comparison as a good measure for determining the value of a subject project. This measure is the least reliable indicator because it fails to account for the varying plant factors of comparable properties. It thus creates the potential anomaly where a $/kw figure produces a higher project value for a project that produces less energy than another project with a higher plant factor, lower installed capacity, and higher annual energy output. Clearly a mills/kwh figure, using net operating income as the numerator, is a more reliable unit for comparison; although it may fail to account for variations in future gross income and operating expenses. To go one step further and to specify a project holding period and to account for future variations in net operating income places the appraiser square in the middle of a yield capitalization analysis, suggesting that that is where he should have started his analysis in the first place.

(2) The Income Capitalization Approach

Our last statement should suggest that we favor income capitalization as the most useful technique for valuing hydroelectric stations.* In addition, given the choice between direct capitalization (which looks only at the first year's net operating income) and yield capitalization (which looks at a stream of discounted future revenues for a designated holding period), we would choose the latter, given the inherently long term nature of most hydroelectric investments. Therefore, unless the client specifies a preference for direct capitalization or there are special conditions which preclude the use of the yield capitalization approach, the appraisal technique of choice is almost invariably a yield capitalization analysis.

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* The exception to this general rule is the valuation of new, utility-owned hydroelectric capacity, where income is a function of cost of service or contribution to rate base. In this instance, the cost of the project will determine the overall annual revenue requirement of the utility company and the technique of choice has to be the cost approach.

In such an analysis, the two key variables are net operating income and discount rate, and minor variations in each will have a substantial impact on the final value determination. In turn, net operating income will be a function of marketable energy output, price paid for output, and operating expenses. The determination of these values for any particular hydro site is by no means a simple task, and the most important task of the appraiser will necessarily be the verification of these values.

At stations which have an operating record, there is no substitute for records of past operating history. Assuming the verifiability of these records, annual output can be reliably predicted and, from that, a reliable projection of future gross income can be derived. However, a close examination of maintenance records is also important as an indication of the probability of experiencing similar operating records in the future as well of the cost and schedule for necessary rehabilitation or previously deferred maintenance work in the future. In addition, where an operating station is currently under capacity, its true value is higher than will be revealed in past operating records. In both instances, a comprehensive yield capitalization analysis will require some use of the cost approach, both in estimating the cost of necessary rehabilitation work and of future improvements to the site.*

Hydroelectric sites which have not yet been developed create a similar problem for the appraiser to that presented by undercapacity sites. That is, future project power generation can not be assumed from past operating records. In such cases, there are numerous technical issues with which the appraiser must have familiarity. Figure II below, lists the types of questions which must be asked by the appraiser in an effort to verify projections of future power output, to identify additional hidden costs which may have to be incurred (usually as a condition of the FERC license), and predictions of future operating income. It will be seen that all of these questions are intended to provide information necessary for determining accurately the net operating income of a hydroelectric project throughout the holding period.

Once the appraiser has confidence in his projection of net operating income from the subject project, the next key variable to be determined is the appropriate yield rate or discount rate to use in calculating the net present value (capitalized value)

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* In the former case, the cost of rehabilitation would be deducted from the net present value of the stream of projected incomes for a final value determination. In the latter case, the future discounted cost of imnprovements and the resulting increase in future revenues would be examined for the degree of their favorable impact on project value.

FIGURE II

ISSUES AFFECTING THE FUTURE ENERGY OUTPUT, HIDDEN COSTS AND FUTURE REVENUES OF UNINSTALLED HYDROELECTRIC CAPACITY

A. ISSUES AFFECTING ELECTRIC OUTPUT

1. How does the efficiency of the turbine equipment vary with head? How much water is used at varying heads?
2. What are the tailwater and headwater curves? How do these and other head losses affect project output?
3. How does the efficiency of the generator vary with load?
4. How does the efficiency of the gearbox vary with load?
5. How much water is available for use by the turbine in an average year? Are there upstream impoundments which can be controlled to the benefit of the subject property?
6. What is the minimum flow release requirement at the dam? Does this requirement vary at different times of the year?
7. What is the minimum flow release requirement below the project? Is it possible for the station to be operated on a store and release basis within the limits of this flow requirement, or must it be operated strictly on a run of the river basis?
8. Are there special attraction flow requirements for the operation of downstream and/or upstream fish passage facilities?
9. Are there any other flow releases required to provide for other uses of the river resources?
10. In the case of adding capacity to an operating station, will the new turbines ever take water away from the existing units? How will this affect total project output?

B. ISSUES AFFECTING FUTURE HIDDEN COSTS

11. What will be the capital cost of installing fish passage facilities and by when must they be installed?
12. Are there any additional capital costs associated with aquatic or wildlife habitat improvement? If so, by when must they be accomplished?
13. Are there any capital costs associated with providing special recreational resources?
14. What are the future operating costs associated with operation of these special facilities (including possible increase in insurance premiums)?

FIGURE II (continued)

15. Is the dam located in a high hazard area and what will be the associated, repeated, administrative costs of dealing with dam safety?
16. Are there special interconnection costs which must be incurred before the project can go on line?
17. Are there special additional operating costs which must be incurred for the privilege of interconnecting with the adjacent utility (such as the cost of minimum liability insurance premiums)?

C. ISSUES AFFECTING FUTURE PROJECT REVENUES

18. What are the terms of the power purchase contract? How long will it last? How much will be paid for the electricity generated? Is it a variable rate? A time of day rate? A seasonal rate? Are there project controls possible to optimize use of the rate structure?
19. Is there a floor price in the contract?
20. Are future rates pegged to the occurrence of specific conditions? What are these conditions and what is the probability of their occurring?
21. For projects where the power will be consumed on site, what is the projected cost of acquiring the same power from other sources? Stated differently, what are the energy cost savings attributable to the subject hydroelectric station? If the site remains interconnected to the supply grid, will there be continuing demand charges which should be factored in?
22. Is the power to be wheeled to a non-adjacent buyer and is the price paid for power net of the cost of this service?
23. Are there special tax benefits or costs associated with the proposed transaction? What is the value of these benefits or costs and how should they be factored in to annual net operating income?

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of the stream of annual net incomes. Typically, this rate will be determined by a comparative method, which is to say that a defensible rate of return on investment is one which is commonly accepted by other similar investors.

Our own survey of acceptable internal rates of return on investment reveals a range of pre-tax expectations between 12% and 18%.

If the appraisal is being completed for a potential buyer, then the buyer has considerable leeway to posit an acceptable rate of return. Simply put, the higher the posited yield rate, the lower the offering price for the subject property, and vice versa. Where the appraisal is done for the seller, the same applies although you would expect the asking price to assume the low end of the range, with the expectation that the final negotiated sales price will be based on a higher yield rate.

Where the client is a lender seeking a completely neutral appraisal of the value of a hydroelectric property which is slated to secure a proposed loan, then a more objective measure is required. In this case a judgement has to be made by the appraiser as to the level of risk involved in the subject hydroelectric property. Within the range of acceptable rates of return derived from a survey of other comparable investors, the following rules of thumb should aid the appraiser in judging which yield rate to posit:

(1) Unlicensed, undeveloped properties, with no guaranteed power market involve the greatest risk and can therefore justify the highest yield rate.

(2) Licensed operating stations, with a long performance history and a secure power market will justify the lowest yield rate.

(3) Sites with any combination of the above conditions can justify some yield rate in between.

Where it is neccessary to apply these rules of thumb, the appraiser would also do well to determine the desired debt coverage ratio of the client lender. That is, debt coverage requirements (net operating income / annual debt service) can help to identify the threshold value and associated debt service above which a project can not be financed. Knowledge of this value can help to narrow the range of appropriate yield rates within which the appraiser has to use judgement and not science.

Beyond these rules of thumb, there are special project conditions which may dictate a much higher posited yield rate. For example, a project requiring the installation of a one mile long 10' ID penstock on a steep grade carries high construction risks which must be reflected in the posited yield rate. Likewise, hydroelectric stations whose customers are teetering on the edge of bankruptcy also merit a higher yield rate in recognition of the associated risks. Indeed, in a recent appraisal of an independently owned hydroelectric station located within the service territory of Public Service Company of New Hampshire and conducted approximately two months prior to that company's declaration of bankruptcy, Mainstream Associates posited a very high yield rate of 27%, which in turn had a very depressing effect on the appraised value of the subject station.

Finally, in the special circumstance where a utility is purchasing an operating hydroelectric station from another utility, the determination of a justifiable yield rate will either be extremely complicated, or irrelevant (in which case the cost aproach would again be the technique of choice). That is, insofar as the book value (for ratemaking purposes) of any such purchase would be allocated a "net investment" or "depreciated original cost" value, the true value to the purchasing utility would not be revealed by using as a yield rate the rate of return on investment authorized by the relevant regulatory commission. Rather, such an acquisition may have been motivated by such intangibles as a desire for a more diverse fuel mix, the transmission savings resulting from the proximity of the station to a load center, the value of the capacity and energy for sale at wholesale prices to other utilities, and/or the value of the capacity for meeting capability responsibility requirements under existing power pool agreements. While the particular motivation of the buying utility will determine how much it is willing to pay for the subject plant, the average cost pricing of regulated utilities does not facilitate yield capitalization as a technique for specifying the true market value of a particular electric plant. Therefore, value determinations for purposes of utility property transactions will usually require use of the cost approach almost exclusively.*

(3) The Cost Approach

As applied to hydroelectric site appraisals, this approach is particularly valuable for determining the value of new utility owned capacity or of operating capacity purchased by a utility. In such cases, the appraiser will usually be limited exclusively to cost based value determinations.

The cost approach is also usually favored when appraising the replacement cost of plant for insurance purposes.

In addition, the cost approach will be a necessary supplement to the yield capitalization approach to site valuation in those instances where (1) the subject station has experienced physical deterioration or functional obsolescence in need of repair or replacement; (2) the subject station is under capacity, and its value is found partially in its expansion potential; and (3) the subject site has wholly undeveloped hydroelectric potential. In all three cases the cost of repair, replacement, or improvements must be factored into the market value of the property.

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* The implications of the current trend in the U. S. A. toward deregulation of electric utilities may change this conclusion, as it is entirely possible that non-regulated utility subsidiaries will purchase plants from their regulated parent company. Under current regulatory principles, it does not appear that the "depreciated original cost" principle would apply to the purchasing subsidiary. In such a circumstance, we believe that the new subsidiary could posit a defensible yield rate, apply it as a discount rate to the stream of revenues provided by its parent (long term or short term avoided cost, net of operating expenses), and from these derive a legitimate market value.

Where the subject station has suffered curable accrued depreciation, the market value of the station is the capitalized value of the project after the repairs have been completed, less the direct and indirect cost of making the corrections (including the foregone revenue associated with downtime during the rehabilitation period). Where the subject station is capable of being expanded, the market value is the capitalized value of the station after it has been improved, less the total cost of completing the improvements. Again, foregone revenue attributable to downtime during the construction period has to be added to the cost of the improvements and thus deducted from the overall capitalized value of the project. Where the land and water rights are undeveloped, the market value is the capitalized value of the project after it is completed, less the total cost of the improvements.

SUMMARY

Having reviewed the structure of the appraisal profession in the United States, we have concluded that knowledge both of appraisal techniques and of the hydroelectric business is a rare combination.

To facilitate the preparation of reliable hydroelectric appraisals, we have reviewed the three standard techniques used by appraisal professionals and identified the special pitfalls to which the appraiser might fall prey in preparing an appraisal report. To this end, we have attempted to outline the most significant questions which must be asked by the appraiser if he is to prepare a defensible appraisal report.

In reviewing the three standard professional appraisal techniques, we have evaluated the applicability of each to the appraisal of hydroelectric sites and concluded that the least valuable is the sales comparison approach. We have also noted that in special circumstances involving utility acquisition of hydroelectric stations or insurance claims by site owners, the cost approach may be relied upon exclusively. In virtually all other circumstances however, the technique of choice is yield capitalization analysis, usually supplemented by the cost approach. Therefore, we have appended Figure III as an example of the application of this method to the appraisal of a hypothetical [illegible] ~~operating~~ hydroelectric station which is slated for expansion in five years.

FIGURE III

HYPOTHETICAL HYDROELECTRIC PROJECT
PROJECT DEVELOPMENT COSTS

OBJECTIVE: To determine the appraised value of the unimproved land and land rights
DEVELOPMENT POTENTIAL: 9 MW

DIRECT COSTS		
330 Land and Land rights (APPRAISED VALUE)	$589,000	
331 Structures & Improvements	$1,200,000	
332 Reservoirs, dams, and waterways	$3,500,000	
333 Water Wheel, Turbines, Generators	$7,650,000	
334 Accessory Electrical Equipment	$490,000	
335 Misc. Power Plant Equipment	$130,000	
336 Roads, Railroads and Bridges	$79,000	
SUB-TOTAL (Direct Costs)		$13,638,000
INDIRECT COSTS		
Engineering	$1,363,800	
Legal and Accounting	$275,000	
SUB-TOTAL (Indirect Costs)		$1,638,800
TOTAL PROJECT DEVELOPMENT COSTS		$15,276,800
FUTURE COST OF 1993 EXPANSION (2.5 MW), TOTAL =	$3,750,000	

ASSUMPTIONS:
(1) 30 year contract @ $0.06/kwh inflating @ 50% of difference w/avoided cost
(2) Residual value @ end of project = 5 X NOI
(3) Plant factor = 50% overall prior to expansion
(4) Plant factor = 46% overall after expansion
(5) Posited yield rate = 17%
(6) Debt financing @ 12% for 20 years
(7) Entire principal balance and new construction financed at same terms effective 1993
(8) Inflation = 5%/year

FIGURE III (continued)
HYPOTHETICAL HYDROELECTRIC PROJECT - 30 YEAR PROSPECTUS

DEBT RATIO		0.8								
YEAR		1989	1990	1991	1992	1993	1994	1995	1996	1997
OUTPUT (KWH)		39,420,000	39,420,000	39,420,000	39,420,000	46,340,400	46,340,400	46,340,400	46,340,400	46,340,400
RATE (All Hours,$/KWH))		0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0669
GROSS REV.		2,365,200	2,365,200	2,365,200	2,365,200	2,780,424	2,780,424	2,780,424	2,780,424	3,100,173
EXPENSES										
O&M (labor, supplies, and utilities)		(120,000)	(126,000)	(132,300)	(138,915)	(145,861)	(153,154)	(160,811)	(168,852)	(177,295)
General & Adm.		(50,000)	(52,500)	(55,125)	(57,881)	(60,775)	(63,814)	(67,005)	(70,355)	(73,873)
Insurances		(75,000)	(78,750)	(82,688)	(86,822)	(91,163)	(95,721)	(100,507)	(105,533)	(110,809)
Property Taxes		(50,000)	(52,500)	(55,125)	(57,881)	(60,775)	(63,814)	(67,005)	(70,355)	(73,873)
Replacement Sinking Fund		(250,000)	(262,500)	(275,625)	(289,406)	(303,877)	(319,070)	(335,024)	(351,775)	(369,364)
Total		(545,000)	(572,250)	(600,863)	(630,906)	(662,451)	(695,573)	(730,352)	(766,870)	(805,213)
NET OPER. INC.	(15,276,800)	1,820,200	1,792,950	1,764,338	1,734,294	2,117,973	2,084,851	2,050,072	2,013,554	2,294,960
DEBT SERVICE	12,221,440	(1,636,191)	(1,636,191)	(1,636,191)	(1,636,191)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)
EQUITY DIVIDEND	(3,055,360)	184,009	156,759	128,146	98,103	235,859	202,736	167,957	131,440	412,845

PROJECT INTERNAL RATE OF RETURN	0.170
PROJECT RETURN ON EQUITY	0.209

FIGURE III (continued)

DEBT RATIO

YEAR		1998	1999	2000	2001	2002	2003	2004	2005	2006
OUTPUT (KWH)		46,340,400	46,340,400	46,340,400	46,340,400	46,340,400	46,340,400	46,340,400	46,340,400	46,340,400
RATE (All Hours,$/KWH))		0.0791	0.0938	0.1117	0.1164	0.1213	0.1265	0.1318	0.1375	0.1434
GROSS REV.		3,665,526	4,346,730	5,176,223	5,394,023	5,621,091	5,862,061	6,106,738	6,371,805	6,645,213
EXPENSES										
O&M (labor, supplies, and utilities)		(186,159)	(195,467)	(205,241)	(215,503)	(226,278)	(237,592)	(249,471)	(261,945)	(275,042)
General & Adm.		(77,566)	(81,445)	(85,517)	(89,793)	(94,282)	(98,997)	(103,946)	(109,144)	(114,601)
Insurances		(116,350)	(122,167)	(128,275)	(134,689)	(141,424)	(148,495)	(155,920)	(163,716)	(171,901)
Property Taxes		(77,566)	(81,445)	(85,517)	(89,793)	(94,282)	(98,997)	(103,946)	(109,144)	(114,601)
Replacement Sinking Fund		(387,832)	(407,224)	(427,585)	(448,964)	(471,412)	(494,983)	(519,732)	(545,719)	(573,005)
Total		(845,474)	(887,748)	(932,135)	(978,742)	(1,027,679)	(1,079,063)	(1,133,016)	(1,189,667)	(1,249,150)
NET OPER. INC.	(15,276,800)	2,820,052	3,458,982	4,244,088	4,415,281	4,593,412	4,782,998	4,973,722	5,182,138	5,396,063
DEBT SERVICE	12,221,440	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)
EQUITY DIVIDEND	(3,055,360)	937,937	1,576,867	2,361,973	2,533,166	2,711,297	2,900,883	3,091,607	3,300,024	3,513,949
PROJECT INTERNAL RATE OF RETURN	0.170									
PROJECT RETURN ON EQUITY	0.209									

FIFURE III (continued)

DEBT RATIO

YEAR		2006	2007	2008	2009	2010	2011	2012	2013	2014
OUTPUT (KWH)		46,340,400	46,340,400	46,340,400	46,340,400	46,340,400	46,340,400	46,340,400	46,340,400	46,340,400
RATE (All Hours,$/KWH))		0.1434	0.1495	0.1559	0.1623	0.1689	0.1759	0.1831	0.1906	0.1984
GROSS REV.		6,645,213	6,927,890	7,224,468	7,520,672	7,829,019	8,150,009	8,484,159	8,832,010	9,194,122
EXPENSES										
O&M (labor, supplies, and utilities)		(275,042)	(288,794)	(303,234)	(318,396)	(334,316)	(351,031)	(368,583)	(387,012)	(406,363)
General & Adm.		(114,601)	(120,331)	(126,348)	(132,665)	(139,298)	(146,263)	(153,576)	(161,255)	(169,318)
Insurances		(171,901)	(180,496)	(189,521)	(198,997)	(208,947)	(219,395)	(230,364)	(241,882)	(253,977)
Property Taxes		(114,601)	(120,331)	(126,348)	(132,665)	(139,298)	(146,263)	(153,576)	(161,255)	(169,318)
Replacement Sinking Fund		(573,005)	(601,655)	(631,738)	(663,324)	(696,491)	(731,315)	(767,881)	(806,275)	(846,589)
Total		(1,249,150)	(1,311,607)	(1,377,188)	(1,446,047)	(1,518,350)	(1,594,267)	(1,673,980)	(1,757,679)	(1,845,563)
NET OPER. INC.	(15,276,800)	5,396,063	5,616,282	5,847,281	6,074,624	6,310,669	6,555,742	6,810,179	7,074,330	7,348,559
DEBT SERVICE	12,221,440	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)	(1,882,115)		
EQUITY DIVIDEND	(3,055,360)	3,513,949	3,734,168	3,965,166	4,192,510	4,428,555	4,673,627	4,928,064	7,074,330	7,348,559
PROJECT INTERNAL RATE OF RETURN	0.170									
PROJECT RETURN ON EQUITY	0.209									

DEBT RATIO

FIGURE III (continued)

YEAR		2015	2016	2017	2018	2019
OUTPUT (KWH)		46,340,400	46,340,400	46,340,400	46,340,400	46,340,400
RATE (All Hours,$/KWH))		0.2065	0.2150	0.2238	0.2330	0.2426
GROSS REV.		9,571,081	9,963,496	10,371,999	10,797,251	11,239,938
EXPENSES						
O&M (labor, supplies, and utilities)		(426,681)	(448,015)	(470,415)	(493,936)	(518,633)
General & Adm.		(177,784)	(186,673)	(196,006)	(205,807)	(216,097)
Insurances		(266,675)	(280,009)	(294,010)	(308,710)	(324,146)
Property Taxes		(177,784)	(186,673)	(196,006)	(205,807)	(216,097)
Replacement Sinking Fund		(888,918)	(933,364)	(980,032)	(1,029,034)	(1,080,486)
Total		(1,937,842)	(2,034,734)	(2,136,470)	(2,243,294)	(2,355,459)
NET OPER. INC.	(15,276,800)	7,633,240	7,928,762	8,235,528	8,553,957	42,769,784
DEBT SERVICE	12,221,440					RESIDUAL VALUE
EQUITY DIVIDEND	(3,055,360)	7,633,240	7,928,762	8,235,528	8,553,957	42,769,784
PROJECT INTERNAL RATE OF RETURN	0.170					
PROJECT RETURN ON EQUITY	0.209					

SESSION 15:

CASE STUDIES - NORTH AMERICA

Chairperson: H. Tracey
Proctor and Redfern Ltd.

Development of a Hydroelectric Project for a Reluctant Owner

By
D.A. Spaulding

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DEVELOPMENT OF A HYDROELECTRIC PROJECT FOR A RELUCTANT OWNER

Douglas A. Spaulding, P.E.*

History of the Site

The original dam at the St. Cloud site was authorized by an Act of Congress in 1884 and electric power generation began in 1888. Northern States Power Company (NSP) took over ownership of the dam in 1924 and operated the facility until 1967. During this period, the 2.2 MW facility utilized a timber crib dam which was repaired on numerous occasions. In 1967, NSP discontinued power generation at the site due to the poor condition of the timber dam. Since the dam impounded a pool which was utilized for their water supply, the city of St. Cloud had a direct interest in maintaining a dam at the site. After several public hearings and lengthy negotiations, an agreement was reached between the city of St. Cloud and NSP for reconstruction and transfer of ownership of the dam to the city. Reconstruction of the dam was initiated in November 1969 and was completed in November of 1971. This construction involved complete replacement of the former timber crib dam with a new concrete overflow spillway.

Development and Licensing

In 1980, the city of St. Cloud was issued a preliminary permit from the Federal Energy Regulatory Commission (FERC) for installation of a hydroelectric facility at the site. The preliminary permit was issued by virtue of the city's municipal preference. St. Cloud does not have a municipal electric utility and the city's interest in developing the hydro project was based solely upon utilizing an existing resource to provide additional income to the city. The city fathers, however, were opposed to risking tax payers money to develop what they considered to be a potentially profitable, but nonessential city project. From this perspective, the city elected to seek outside assistance in development of the project. Based upon a competitive submittal, Actaeon Corporation of Wayzata, Minnesota, was selected to act as

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the city's agent in the development of the project. An agency relationship rather than a more typical development agreement was required due to the municipal preference considerations used by the city to obtain the preliminary permit. Under the agency arrangement, Actaeon Corporation undertook licensing and development of the project with its own resources. In return for these services, Actaeon was provided a long term management contract to operate and manage the hydro facility. A license application for the 8.6 MW site was submitted to the FERC in May of 1983. A FERC license was received by the city in December of 1984.

The licensing process and the subsequent permitting process included studies relating to both water quality and fishery issues. License requirements required both preoperational and post-operational studies for dissolved oxygen and fishery impacts.

Equipment Selection

Both the selection of the generating equipment and the subsequent selection of the general contractor were heavily influenced by the nature of the project financing. As discussed later in this paper, the project was financed by a revenue bond issued by the state of Minnesota. Because of this, the equipment selection required a careful review of the past performance of various potential equipment suppliers. This review involved a prequalification process which included investigation of previously furnished equipment similar to that proposed for St. Cloud. The generating equipment bid package required that each potential supplier identify a turbine similar to the one proposed for the St. Cloud site which had been in successful operation for at least one year prior to the bid date. This requirement had the disadvantage of restricting certain suppliers from proposing newer designs. The requirement, however, was necessary to ensure that the requirements of the bond issue be met. Bid documents for the generating equipment were issued in the spring of 1986. Formal bids were received from three potential suppliers. The bid documents allowed for utilization of either pit type Kaplan turbines or S type Kaplan units. The bid specifications did not specify a number of units, but contained restrictions on the total generating capacity and total equipment cost. These restrictions were based upon requirements of both the FERC license and financial requirements related to the amount of money available in the bond issue. Three proposals were received including two utilizing pit Kaplan type units and one for a S unit. A detailed evaluation of each of the proposals was performed. The evaluation process included a preliminary design of powerhouse configurations for each of the proposed units. The annual generation was also computed and included in the evaluation. Based on this overall evaluation, two 3540 mm pit turbines proposed by Voith Hydro were selected for the project.

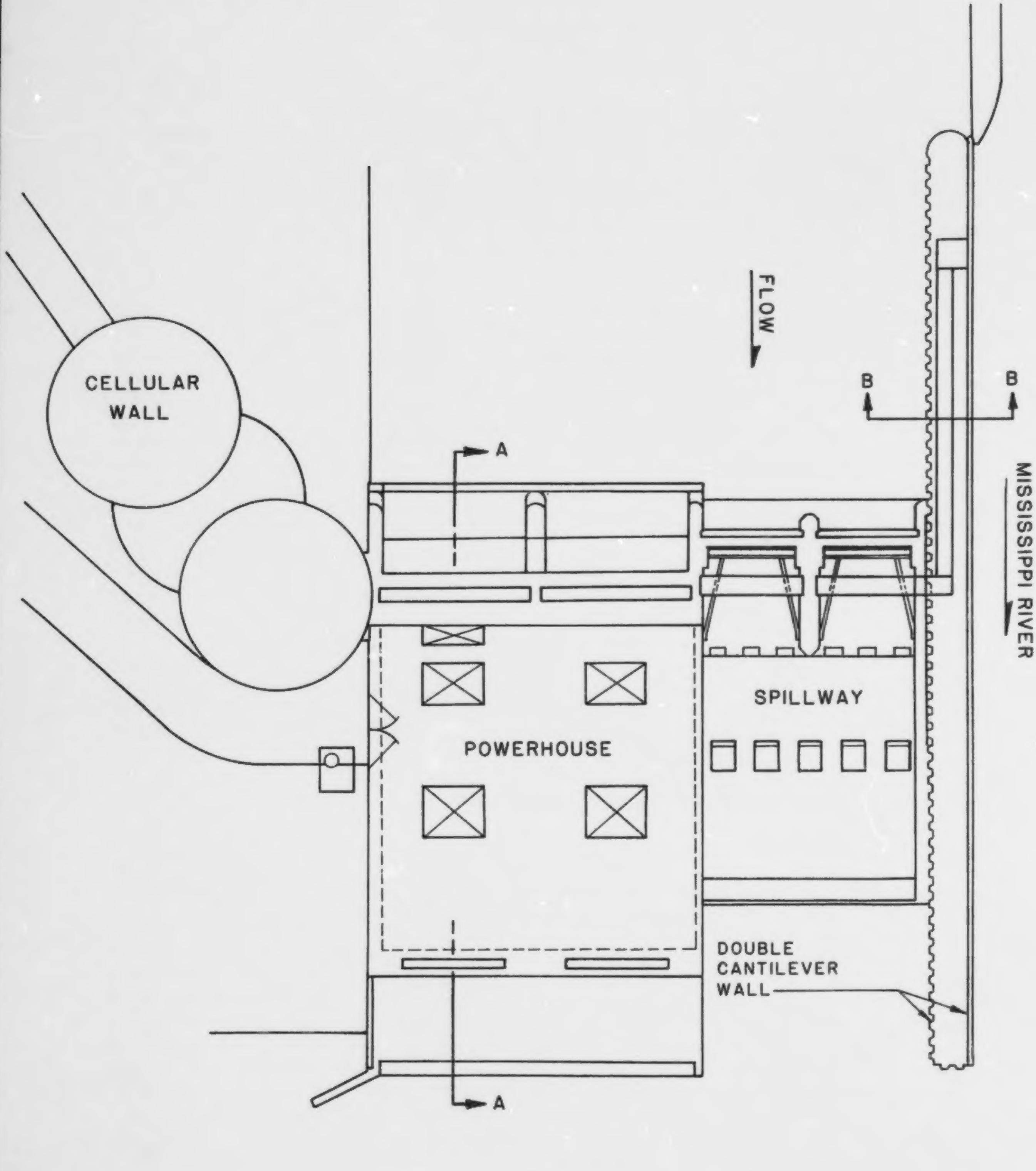
In the course of the evaluation, it was determined that pit turbines offered a clear advantage over S units for this type of an application. The pit turbines included a 3540 mm runner, a epicyclical speed increaser and a 720 rpm generator. A plan of the facility and section of the pit turbine are shown in Figure 1 and 2, respectively.

General Contractor Selection

Subsequent to the selection of the equipment supplier, bid documents were prepared for the general construction contractor. At this point in the development of the project, it was clear that the nature of the project financing would require a turnkey approach to the construction. It was also clear that the turnkey contractor would be required to assume substantial guarantees and warranties in relation to project completion and performance. For this reason, a prequalification brochure was sent to over 20 potential contractors. The prequalification brochure dealt with issues relating both to past experience, financial capability and willingness to assume extraordinary guarantee and warranty provisions. Based upon this prequalification brochure, bid documents were issued to three general contractors. Inherent in the bidding process was the acknowledgment that the selected general contractor would accept assignment of both the Warzyn Engineering design contract and the Voith equipment supply contract to form a turnkey construction team. Construction proposals were received from three bidders and negotiations were continued with two of the three proposers. M. A. Mortenson of Minneapolis, Minnesota was selected as the general contractor subsequent to extensive discussions and negotiations. The negotiation process included evaluation of alternatives to reduce project costs without compromising project functions.

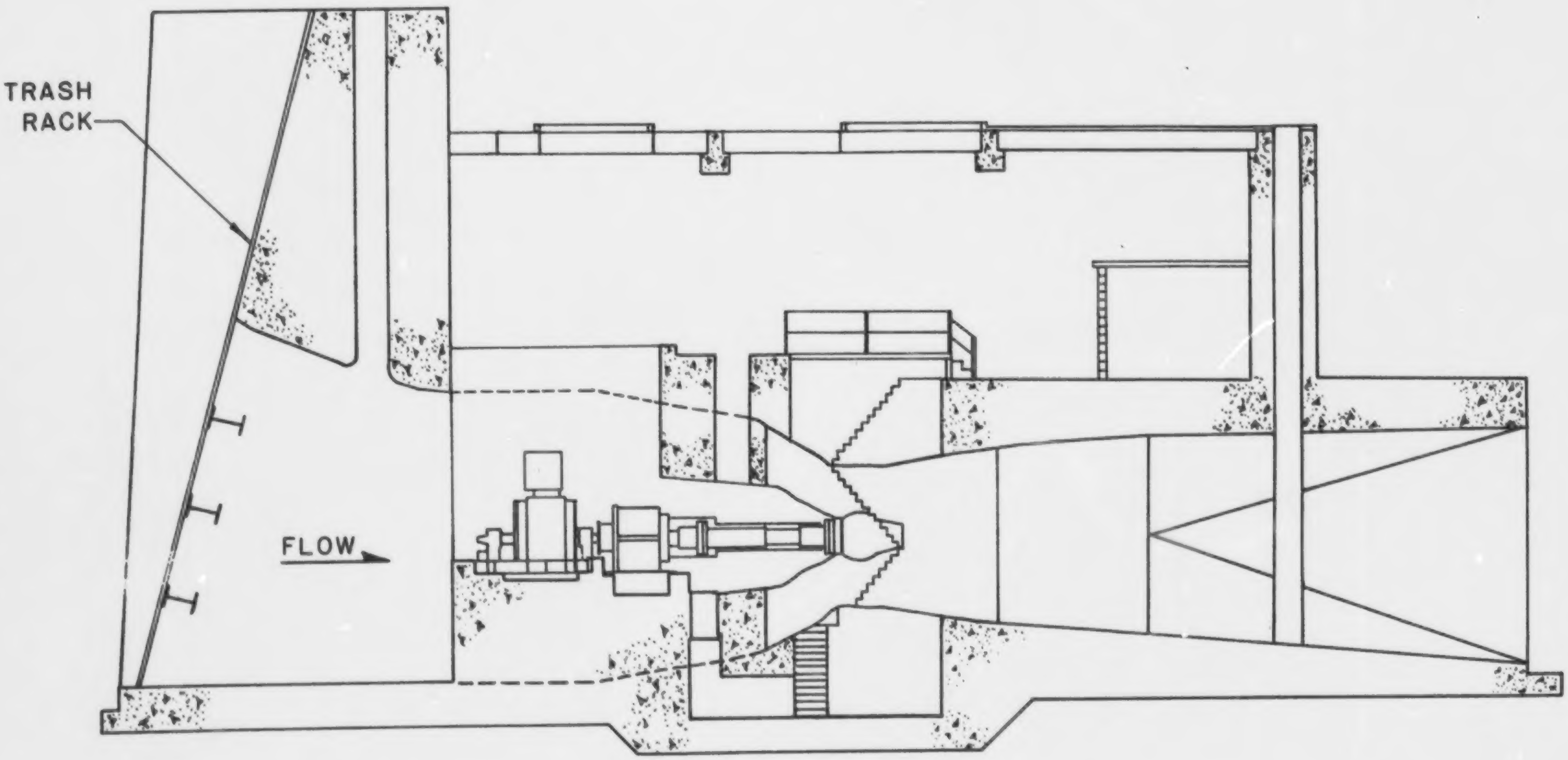
Project Financing

Financing proved to be the most difficult aspect of the project development. As indicated previously, the city of St. Cloud wished to develop the hydropower potential at the site, but would not risk taxpayers' money for what they considered to be a profit making venture. This philosophical position required that the normal "owner risks" be allocated in a different manner than in a conventional owner-contractor relationship. An inherent part of the financing was the need to protect the long term interest of the bond holders for the project. The financing process, therefore, involved lengthy interrelated negotiations regarding guarantees, warranties and cost provisions between the city, the general contractor, equipment supplier and the design engineer. The following is a description of how major project risks were assigned during the financing process.


CELLULAR WALL
FLOW
B
B
A
A
MISSISSIPPI RIVER
SPILLWAY
POWERHOUSE
DOUBLE CANTILEVER WALL

PLAN OF SITE

FIGURE 1


TRASH RACK
FLOW

SECTION A-A

CROSS SECTION OF POWERHOUSE/
PIT TURBINE

FIGURE 2

Cost Overruns

The major concern in any project development is the potential for cost overruns due to changing site conditions and other factors. Under a normal development scenario, the owner retains a contingency fund to pay for unexpected increases in project costs. In most cases, the owner has the responsibility to fund additional cost overruns even in amounts beyond the contingency fund. Since the St. Cloud project was a "project financing", the only funds available for project construction were those which were obtained from the bond issue. The city of St. Cloud did not, and would not, provide any guarantees relating to the use of city funds to stand behind cost overruns. In order to satisfy the needs of the project financing in regard to cost overruns, the turnkey contractor, M. A. Mortenson Company, provided a guaranteed maximum price contract. This contract provided that project costs could be increased only under a set of narrowly defined conditions which included such things as change of scope of the project and changes required to the intake during hydraulic modeling tests. This contract provided the assurance for the bond holder and construction lender that the project would be completed within the available project funds.

Equipment Performance

As in all hydroelectric projects, the project revenues were estimated based upon specified equipment efficiencies in combination with hydrologic data. The equipment efficiencies were guaranteed utilizing provisions which required a weighted average efficiency based on various flow conditions and operating points. Shortfall in the proposed efficiency from the generating units would result in liquidated damage payments related to the value of lost revenue. The liquidated damages were computed in a manner which ensured that the bond holder's interests would not be affected by any shortfall in equipment efficiency. This computation required a payment of $28,000 per 0.10 percent shortfall in the weighted equipment efficiency. The performance test for the equipment was performed by St. Anthony Falls Hydraulic Laboratory under contract with the city of St. Cloud. The tests included current meter measurements utilizing a traveling rack across the area of the intake. Voith Hydro was responsible for the overall generating efficiency and configuration of the waterway passages from inside of the trashrack to the downstream end of the draft tube. Headlosses and hydraulic design for areas upstream and downstream of these locations was the responsibility of the design engineer.

Intake Performance

Recent experience with several hydroelectric developments indicates that the design of the intake is often extremely critical to the successful operation of the hydroelectric facility. Quantifying intake performance and related headlosses, however, is very difficult and very cumbersome to deal with from a contractual standpoint. The bond holders' consulting engineer strongly believed that guarantees were necessary to ensure that the intake functioned as intended. Consideration was given to formulating total head and output guarantees for the facility which would have encompassed both the equipment suppliers guarantees and the intake design. While theoretically possible, these types of guarantee provisions were found to be very complicated to formulate and describe from a contractual standpoint. An alternative guarantee mechanism was developed based upon the relative performance of the two unit hydro facility. Past experience with several hydroelectric facilities indicated that intakes generally would perform well under single unit operation, but could suffer a shortfall due to faulty design when both units were in simultaneous operation. This observation was utilized to develop the "two unit guarantee provision". This provision stated that:

> "The General Contractor guarantees that the total combined output from both units operating simultaneously shall equal or exceed 95% of the total individual output as a unit operating individually."

The guarantee essentially stated that one plus one should equal two. This guarantee included provisions for computing and adjusting outputs for variations in net head. Liquidated damages were provided for a shortfall in this guarantee. The intake guarantee was the obligation of the general turnkey contractor. To provide the basis of a design to provide a satisfactory intake, a model test was performed by the design engineer. Results of these model tests are described later in this paper. Project financing was completed on December 23, 1986 and a Notice-to-Proceed was issued to the general contractor.

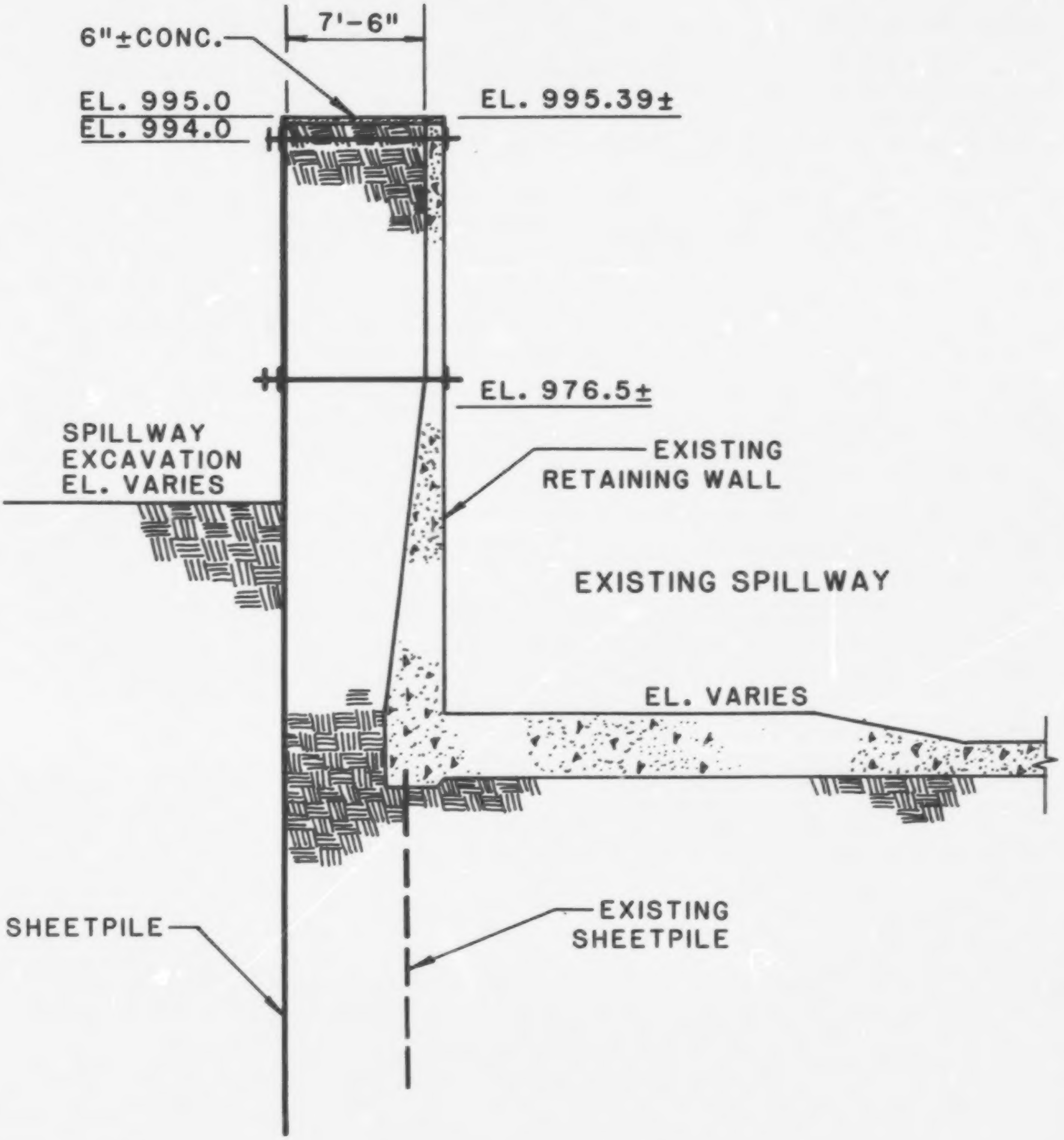
Design and Construction

The design and construction effort was based upon a fast track approach which included preparation of five separate design packages. This division of design tasks allowed for the concurrent preparation of design elements with on-site construction. FERC review of the design, as required by the license, was conducted in a phased approach. In addition to FERC review, the Minnesota DNR dam safety review was also required.

The initial design package including drawings for cofferdams and deep excavations was submitted to the FERC in December, 1986. This early submittal allowed on-site construction to commence on February 2, 1986. One innovative design technique included the utilization of a double row cantilever sheetpile wall with an exposed face of over 40 feet. A cross section of this wall is shown in Figure 3. The location of the wall is also shown in Figure 1. This wall consisted of PZ-40 sheeting tied together with anchors and cantilevered into the underlying clay shale. The use of this cantilevered approach was made possible by the extremely strong clay shale which underlays the project site. This wall eliminated the need for a costly cellular cell cofferdam on the riverward side of the excavation. The performance of this wall was monitored by measurement of the deflections at the top of the wall on a daily basis during construction. The allowable height of exposed face of the wall was based upon requirements related to tailwater levels. For higher tailwater levels, the contractor was required to place fill against the landward side of the wall to increase the stability of the wall. The use of this wall allowed the contractor to expedite construction schedules and to construct the tainter gate spillway prior to completion of the powerhouse.

One major early feature of the design process included the performance of a hydraulic model test for the powerhouse intake area. The model test, which was performed at a scale of 1:24 by St. Anthony Falls Hydraulic Laboratory, was utilized to verify the intake design. The results of the model test indicated that additional excavation would be required upstream of the intake to provide a smoother and more regular transition into the turbine intake. This transition, in depth, was required to accommodate the change in river bottom from 7 feet at mid-river channel to over 50 feet at the turbine intake. The changes recommended by the model study resulted in a reduction of approximately 0.20 of a foot in headlosses. Although this savings in head loss would be minimal on higher head sites, for the 18 foot head at the St. Cloud project the 0.20 of a foot represented approximately $30,000 a year in income. The model test, therefore, will pay for itself within the first two years of operation.

Project construction proceeded through the summer of 1987. Generating equipment deliveries occurred in December, 1981 and January, 1988. The construction was essentially complete in mid-May of 1988 and the facility was in commercial operation on June 1, 1988. The overall construction period of 17 months was 5 months ahead of the estimated 22 month schedule. This achievement was aided by expeditious fast track design and construction schedule and detailed planning and scheduling of the on-site construction activities. Low water and good weather also contributed to the early completion.


7'-6"
6"±CONC.
EL. 995.0
EL. 994.0
EL. 995.39±
EL. 976.5±
SPILLWAY
EXCAVATION
EL. VARIES
EXISTING
RETAINING WALL
EXISTING SPILLWAY
EL. VARIES
SHEETPILE
EXISTING
SHEETPILE

SECTION B-B

CROSS SECTION THRU WALL

FIGURE 3

Lessons Learned

The St. Cloud project was a successful endeavor for all involved in the development, design, and construction. The unique nature of the construction financing provided several valuable lessons for future developments. These include:

1. Although a true "project financing" is difficult, it can be accomplished if a group of willing participants are brought together to form a total design and development team.

2. A true project financing requires a financially strong project.

3. The implementation of the fast track design built approach and close coordination between the construction team members can provide significant savings in construction time.

4. The use of hydraulic model tests for the intake conditions at low head sites can provide significant increases in revenue.

Stillwater Reservoir Hydro-Electric Project

By
T. Bates, H. Lensink

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STILLWATER RESERVOIR HYDRO-ELECTRIC PROJECT

Homer Lensink, C.E.T.[*]
Thomas Bates, P.E.[**]

ABSTRACT

During 1986 the Stillwater Reservoir Hydro-Electric Project was developed. This project included a 1970 kW, Kaplan turbine, synchronous generator, and fully-automated electronic controls. This paper describes the main features which were incorporated into the turbine and civil design & powerhouse construction. The Reservoir is located approx. 100 kilometers north-east of Watertown, New York. The project required an innovative civil design which not only mitigated environmental and aesthetic issues, but was practical to construct in such a remote area with dramatically steep topography. The turbine design incorporated unique fabrications for ease of installation & maintenance, safety and control features for un-attended operation, and other special design considerations. This unique design, combined with a concerted effort by all parties involved, allowed manufacture and construction to progress throughout the year.

INTRODUCTION

The Stillwater Reservoir Hydro-Electric Facility became fully operational in February 1987. The design and development of this project represent a unique solution to a difficult set of siting, machine selection, environmental protection, flow management and construction logistic problems. This paper summarizes highlights of the civil and mechanical design aspects, which resulted in the successful development of a difficult small scale hydro-electric project.

THE PROJECT

The Stillwater Reservoir is located approximately 100 kilometres north-east of Watertown, New York, in a remote wilderness area of the Adirondack Mountains. The hydro-electric facility is located at the outlet of the Stillwater Reservoir in the town of Webb, Herkimer County at the head waters of the Beaver River, which is a tributary to the Black River.

The reservoir was created prior to 1885 with the construction of a log dam which was then replaced with a concrete structure around 1885. In 1924 the current structure was constructed. This dam is approx. 6 metres higher than the original structures and involves three additional earth embankments which service as nonoverflow and emergency-release spillways. The concrete gravity structure serves as the outlet control structure, and is the focus of this project. The dam is 102 metres in length and 11.6 metres in height. The complex of impounding structures create a reservoir which regulates a high-yield watershed of 445 square kilometres, surface area of 2600 hectares, and a volume of 108,000 acre-feet (133 million cubic metres) at normal high water (elevation 1677.3 feet USGS). The Hudson River-Black River Regulating District (HRBRRD) owns the facility and manages flows in the Beaver and Black Rivers through the close regulation of reservoir levels.

The new hydroelectric facility replaces the traditional outlet control mechanism for the reservoir, and represents a unique method of flow management. All generation operations are governed by the HRBRRD's dictated instantaneous flow-release schedules, which are now facilitated by the station and its computer-based control systems.

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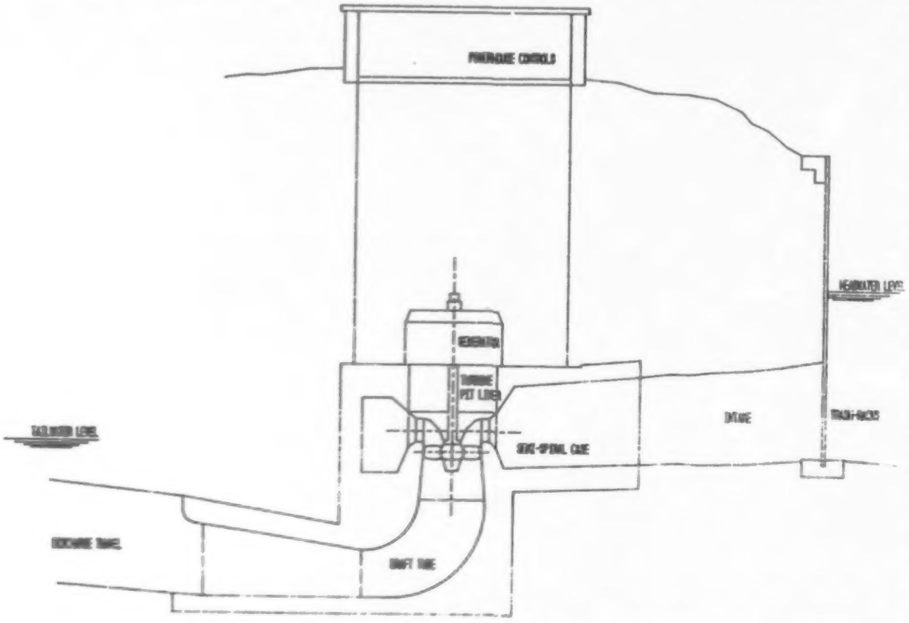
[*] **Project Manager, TURBEX International Inc., Barrie, Ontario**
[**] **Project Engineer, Besha Associates Engineering Corp., Albany, New York**

Management of the reservoir has been programmed to optimize a number of benefits including flood control, pollution abatement, hydroelectric generation (at the release point, as well as several downriver locations) and recreation. The region is noted for its harsh weather extremes, dramatically steep topography, and abundant and diverse wildlife. Thousands of visitors frequent the region throughout th year to enjoy its natural beauty and many recreational opportunities. The integration of hydro generating facilities at the site required a design that was unobtrusive and able to perform as an isolated station across wide head and flow bands, as dictated by reservoir operational rule curves.

THE DESIGN

The project had to be designed and constructed to best integrate into an existing operating regime which results in high variability in both flow and available head through the course of any given year. Historically, the water level was regulated through a series of gates and a rock tunnel around the south abutment of the 11.6 metre high concrete spillway. The flow range is 6 to 26 cms, and head varies from a maximum of 11.6 metres to a minimum of 3.65 metres. The original bypass tunnel had been plugged and abandoned. The flow regulation function was then performed through the use of a set of gates and outlet pipes located in the base of the concrete outlet spillway



Stillwater Powerhouse Elevation View

The project demanded an innovative design which would regulate flow releases, optimize generation under the varying head and flow conditions, mitigate aesthetic and environmental issues, and be practical to construct and operate in the isolated area. The design which was constructed has met all these demands.

The powerhouse is located on a relatively level area adjacent to the south abutment of the concrete spillway. The powerhouse consists of a vertical bore, 10 metres in diameter, progressed to a depth of 22 metres in massive granitic-gneiss bedrock. The bore was located to take advantage of the existing bypass tunnel. The former outlet is now utilized as the inlet and outlet for the turbine. At the base of the bore is a cast-in-place, reinforced concrete draft tube with a steel elbow liner. The spiral case consists of cast-in-place, reinforced-concrete with embedded steel stay vanes and turbine pit liner. The roof of the spiral case also functions as the generator support and seals the powerhouse from water intrusion. The hydraulic power unit, generator and ancillary systems are located on the generator level. From the generator level to the ground surface, (a height of approximately 14 meters) the rock walls were left unlined. At the surface, a low-profile, concrete structure houses the control equipment and covers the bore. The high-voltage switchgear is outdoor, low-profile, metal-enclosed. The inlet gates are housed underground and extend down to the inlet tunnel through a slot blasted in the rock.

CONSTRUCTION

Construction began in September of 1985. The bore was progressed to its full depth utilizing conventional drill and load techniques for both pre-split and production blasting operations. Horizontal outlet and inlet tunnels were then tapped into the existing bypass tunnel and into the waterway last. All rock was removed upward through the vertical bore, and a temporary plug was left at the tunnel ends to prevent water intrusion during construction. Reinforced concrete work was initiated along with the embedment of the draft tube, stay vanes, and turbine pit liner. Upon completion of the generator level, the turbine drive train installation began. Walls and roof were then constructed over the bore. Generator, and electrical control equipment were installed last. An agreement was reached with the Adirondack Park Agency to upgrade and replace a fourteen kilometre long overhead transmission line to the site. The line follows an existing overhead route, but had to be upgraded to comply with numerous technical and environmental requirements of Niagara Mohawk Power Corporation (the receiving utility) and the Adirondack Park Agency (which maintains planning and permitting authority over such construction within the park boundary). The project involved the excavation of 4500 cubic meters of rock and placement of 750 cubic metres of concrete. Total time for construction was less than 14 months.

CONSTRUCTION BENEFITS

1. All procedures performed in the dry. Crane support was readily available.
2. Minimal stream disturbance; exposure to flooding was minimized.
3. Construction progressed throughout the year despite very low temperatures and heavy snowfall.
4. Blasted/excavated rock was utilized on-site to reinforce an earthen portion of the dam.

CONSTRUCTION DIFFICULTIES

1. One of the largest obstacles was the logistics of moving materials to the site. A fourteen kilometre, rugged, dirt road, normally used for passenger vehicles, was the only access to the site. This limited the size and clearances of all trucks and trailers used. All materials had to be handled with special care, especially during the winter months.
2. Following excavation of the vertical rock bore, the walls seeped a minor amount of groundwater. This was remedied by using chemical grouts along with chase drains to divert any additional weeping.
3. Another difficulty was the extreme temperatures encountered, accompanied by deep snow pack, although work did progress.

OPERATION BENEFITS

1. Reservoir management operation are now easily and more accurately controlled through the use of computer control devices as opposed to physical manipulation of multiple gates.
2. The release capacity of the structure has been increased.
3. Energy and revenue benefits now result from flow control operations which previously represented only a cost to the Regulating District.

OPERATIONAL OBSTACLES

1. Tailrace gates were initially designed into the project; however budget constraints cancelled their installation. Future maintenance operations are not precluded because of this, but will be more difficult to achieve without the gates.

ENVIRONMENTAL CONCERNS

Many environmental issues were mitigated through the use of a low-profile design placed out and away from the streambed. In addition to the normal seismic monitoring during construction, an environmental monitoring program was initiated to assure that the resident loon population was fully protected. In addition to a staff of biologists, who monitored the birds and their nesting locations each day throughout their residence, "floating nesting islands" were constructed and deployed. This research effort was sponsored by Stillwater Associates, the project developer. These islands provided an alternative habitat for nesting pairs of loons, and were shown to offer promise in protecting loon eggs from water level fluctuations. The monitoring effort verified that blasting and other construction operations had no negative impact on the resident birds.

TURBINE DESIGN

The **scope of supply** for the turbine manufacturer included the 1970 kW vertical Kaplan turbine with a throat diameter of 2 metres, vertical synchronous generator with static exciter, and ancillary equipment. The ancillary equipment included hydraulic power unit, compressed air system for the generator brakes, and cooling water system. The electrical controls/switchgear were supplied by others.

The geometry of the existing civil works at the site, the high cost of further excavation, and the concern of possible air-ingestion during low-head operation determined that a semi-spiral case was best suited for this site. The floor rises, and the ceiling descends as the flow progresses around the distributor. This hydraulic shape required some intense concrete forming work. Because of the severe site conditions ease of installation & maintenance were a prime concern in the design of the turbine equipment. Fabrications were utilized where possible to minimize component weight. The turbine runner had 5 cast stainless steel blades. The operating rod for blade pitch adjustment passes through a hole in both the turbine and generator shafts. The blade pitch actuator is mounted on the non-drive end of the generator shaft. This actuator is designed so that any maintenance of seals or bearings can be done without removal from the shaft. The main bearing and shaft sleeve were also designed for ease of maintenance. Both are split journals which can be removed and re-installed without removing or disturbing the shaft or bearing housing.

The **turbine pit liner** is a vertical cylinder which extends upwards from the top flange of the stay ring to the generator floor (approx. 3 m.) This fabricated component is not found in traditional vertical machines of this configuration. The purpose for incorporating it into this design was to provide a fixed-link between the turbine and generator. The intent was to eliminate the secondary aligning required at the mounting flange of the generator. The turbine/generator assembly is therefore a tower assembly. This feature significantly reduced installation time. The hydraulic down-thrust and the torque of the machine is transmitted into the generator floor through this pit liner. It also provided a simple method of the concrete forming of an access area at the top of the turbine.

The **draft tube** is embedded in concrete at the base of the excavated bore. It is a fabricated steel liner elbow . Because of transport size limitations it was shipped in three pieces and welded at site. The downstream straight section of the tube was formed in concrete. A considerable number of rock anchors were used to hold the draft tube elbow in its installed position against the buoyant forces of the poured concrete. The upper discharge cone of the draft tube elbow was site-welded in place only after the concrete was set to compensate for horizontal mis-alignment of the "cast" elbow. Because of the tower nature of the turbine/generator assembly, the vertical alignment of the whole unit was a function of the levelness of the horizontal flange of the discharge cone.

The **generator** was specified as being direct-drive at 212 rpm for improved plant reliability reasons. The generator was also specified as requiring a forged flange on the drive-end. This provided an integral method of transmitting the vertical hydraulic thrust load and the gravitational weight of the turbine runner and shaft to the thrust bearing. The generator bearings were supplied with oil-water heat exchangers. This system was also supplied with temperature regulating valves to prevent the lubrication oil from becoming too viscous. This was a concern because of the climatic conditions of the site.

AUTOMATION FEATURES

Because of the un-attended operation of the plant the equipment was supplied with the following **remote monitoring transmitters**; blade and gate actuator position, generator bearing temp., lube & hydraulic oil temperature, and headwater, tailwater elevation, & trash-rack differential pressure. Electrical protective devices were also supplied; cooling water flow switches, lube oil level switch, and hydraulic oil sump level switch, hydraulic and cooling water pressure switch.

The un-attended nature of plant operation and the absence of automated intake gates called for a mechanical method of fail-safe **gate closure**. This was in addition to the traditional stored energy in the accumulators of the hydraulic system. A compression spring was chosen. It was sized to provide extra force capacity to slip the friction-locking device in the gate linkage when closing the gates against debris. This situation was encountered during commissioning a few times before the semi-spiral case was cleaned of inevitable construction material. The compression spring mechanism was not initially installed correctly causing mis-alignment and bowing. The installation error was remedied and an internal guide was installed. Future operation of the spring was acceptable.

The programmable controller operates the turbine in response to the instantaneous flow release schedule mentioned previously. The controller calculates net head from the headwater and tailwater elevation transducers. The controller accesses the **electronic operating cam** with a flow and net head value. It receives from one table a gate position, from another table a blade position, and from a third table and expected unit output. If expected unit output differs significantly from actual unit output an alarm is signalled and the unit is shut-down indicating transducer loss of calibration. Because the head varies considerably at this site the cam tables were quite large. Head values are given in increments of 0.3 meters, and the flow in increments of approx. 1 m^3/s. The tables were generated on a computer spreadsheet from the model hill diagram; and transferred via modem directly into the software of the programmable controller.

GENERATOR OUTPUT (kW)

FLOW (cfs)	HEAD (ft.) 12	13	14	15	16
210	121	137	152	169	185
240	140	160	180	198	216
270	165	191	216	239	262
300	192	222	246	274	301
330	218	246	279	307	338

WICKET GATE ACTUATOR POSITION (%)

FLOW (cfs)	HEAD (ft.) 12	13	14	15	16
210	47.0	45.3	43.5	0.0	36.5
240	52.0	50.0	48.0	45.5	43.0
270	61.1	59.5	57.1	53.3	49.3
300	66.3	63.2	62.1	60.1	57.9
330	71.2	68.5	66.8	64.9	63.2

BLADE ACTUATOR POSITION (%)

FLOW (cfs)	HEAD (ft. 12	13	14	15	16
210	17.9	18.0	18.2	18.2	18.2
240	21.0	21.3	21.3	21.2	21.0
270	25.1	24.4	24.0	23.7	23.0
300	26.4	27.1	27.1	27.1	27.1
330	29.1	29.8	30.8	31.1	31.4

Sample Section Of
Operating Cam

SPECIAL DESIGN CONSIDERATIONS

There is a considerable length of tunnel between the river and the draft tube exit. As mentioned an existing discharge tunnel was re-used. This extra length was of concern to the designers during emergency shut-down. During runaway condition an axial-flow machine passes significantly more water than during operating conditions. This coupled with the long discharge tunnel could potentially cause negative pressure and reverse thrust conditions. A computerized surge analysis was performed in order to optimize the gate closing time so that negative pressures would be minimized and air addition to the draft tube would become unnecessary. This relieved concerns about the large column of water leaving the turbine quickly and hammering back up on the runner before discharging to atmosphere.

The high runaway speed characteristics of the axial-flow turbine were also of concern to the designers. The generator was specified as being capable of withstanding the overspeed of the turbine. The controls of the hydraulic power unit were designed to reduce this however. The model runaway speeds were the lowest with the maximum blade pitch settings. For this reason the blades are opened to their maximum pitch setting during full load rejection & emergency shut-down. During commissioning the full load was rejected with overspeed limited to less than 100 % . This design feature considerably reduces stress on the machine.

CONCLUSION

Small hydro design is a distinct field of engineering. The economic reality mandates simple designs, and where possible the use of standard products/methods. Because each site and method of operation is unique, however, special attention is required in all phases and disciplines of design. In the case of the Stillwater Reservoir Hydro-Electric Project all of the design disciplines required innovative and special solutions. The extreme topography & geographical location of the site, the climatic conditions, the re-use of existing tunnels, the regulated release operational constraint, the isolated/un-attended nature of plant operation, and the environmental concerns were all issues that affected the project development. Cost and time budgets were met. The unique design, combined with a concerted effort by all parties involved, allowed construction to proceed throughout the year. Based on the results of installation and the first 1 1/2 years of operations for flow regulation and energy generation, the project was successful.

STATION DATA

Head Range:	3.65 - 11.6 metres
Flow Range:	6 - 26 m^3/s
Capacity:	1970 kW
Annual Energy:	6,500,000 KWH
Turbine Unit:	Vertical, semi-spiral, fully-regulated, 2000 mm throat diameter.
Generator:	Vertical, synchronous, 4160 Volt, 34 pole, static excitation
Powerhouse:	Underground, natural rock caisson
Owner:	Hudson River-Black River Regulating District
Developer:	Stillwater Associates
General Contractor:	Laquidara, Inc.
Turbine Supplier:	Barber Hydraulic Turbine Inc.
Generator Supplier:	Siemens
Engineer:	Besha Associates Engineering Corp.

Small Hydro Development on the Magpie River

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SUMMARY

The Magpie River Development, located near the Town of Wawa in Northern Ontario, involves the construction of three power plants on the Magpie River with a total installed capacity of 43 MW. The Mission Falls plant is located near the mouth of the river, the Magpie Falls plant some 3 km upstream and the Steephill Falls plant another 25 km upstream.

The plants are owned by Great Lakes Power Limited (GLP), a private utility which generates and markets power in the Algoma District of northern Ontario, including the City of Sault Ste. Marie and the Town of Wawa.

As a private development, the project was not automatically designated under the Environmental Assessment (EA) Act of Ontario, however, because of the environmental issues involved, GLP decided to undertake full EA studies, as if the project was designated under the Act.

The studies were completed within 13 months. The project was not designated under the EA Act and approval was granted by the Ministry of the Environment (MOE) subject to certain Crown Conditions and third party agreements. Construction commenced in June 1988, six months after completion of the EA report.

The EA studies were undertaken simultaneously with further engineering studies and an integrated approach to decision making was adopted. Specific examples include the selection of the type of generating unit and the mitigation measures introduced for a control weir located at the brink of the scenic Magpie Falls.

While the review process carried out for the Magpie River Development was not entirely typical of the formal designated process, the studies undertaken were consistent with the requirements under the Act. A review of experience obtained is presented.

1 - BACKGROUND

The Magpie River is located near Wawa, Ontario, about 250 km due north of Sault Ste. Marie (Figure 1). It drains an area of 1930 km^2 and discharges into the Michipicoten River at Mission Bay, about 2 km from the shore of Lake Superior (Figure 2). From its headwaters to the confluence with the Michipicoten, the Magpie River drops about 230 m over a length of about 160 km (Figure 3). The mean annual flow is 27 m^3/s, most of which occurs during the spring flood.

The Magpie River basin has played an important role in the early history of Canada. A trading post was located at Mission Bay and mining development started in the late 1800s, with the main Magpie iron ore mine located about midway at the western side of the Magpie River basin. Transport of ore was by railway, crossing the Magpie River at McKinnons Bridge. Supply of power to the mine was provided by a power development on the Magpie River at Steephill Falls, which was completed in 1915. This development consisted of a 15-m high concrete buttress dam and a 2-unit powerhouse. It was abandoned in 1926 when poor economic conditions forced the closure of the mine.

Flow regulation for the development was provided by a 5-m high control structure on Esnagi Lake, located in the northern half of the basin. This structure is still in operation and is currently owned by the Ministry of Natural Resources (MNR).

The Magpie River basin is located within the supply area of GLP, a power utility which operates nine hydroelectric power plants in the West Algoma District (Figure 4). Power generation is limited by water availability and GLP imports about 30% of its energy requirements from Ontario Hydro. Early studies for increasing generation within the supply region were made by Acres International Limited (Acres) in 1978 and 1980 and the Magpie River Development was identified as the most promising alternative. The results of these studies were confirmed by more detailed studies in 1984 and 1985 and a decision was made to undertake final definition and EA studies in October 1985.

2 - ENVIRONMENTAL ASSESSMENT REQUIREMENTS

Projects undertaken by provincial and municipal authorities in Ontario are automatically subject to the EA Act of Ontario. Projects that are undertaken by private industry are not automatically so designated. However, designation under the Act can occur if significant potential environmental impacts are identified. When this happens, approval must be obtained before construction permits can be issued.

In the case of the Magpie River Development, it was considered that designation could delay or stop the project by further impeding an already tight project schedule. To prevent this situation from jeopardizing the economic viability of the project, GLP approached MOE to voluntarily undertake the required studies as if the project was designated under the Act.

MOE agreed to participate in this 'informal' process. Figure 5 shows information prepared for presentation to the public to explain the similarities and differences between the formal designated EA process and that undertaken by GLP.

3 - PROJECT DESCRIPTION

The Magpie River Development has four components as shown in Figure 2

- Esnagi Lake regulation
- Steephill Falls power development
- Magpie Falls power development
- Mission Falls power development.

3.1 - Esnagi Lake Regulation

Esnagi Lake is located in the upstream part of the Magpie River basin and is a manmade reservoir with flows and levels regulated by a control structure. As such, Esnagi Lake will provide upstream storage of flows for the Magpie River Development. The surface area of the lake is about 43 km^2 and its drainage area is about 35% of the basin area. Currently, the lake is drawn down by 0.6 m during the winter months. For this purpose, two stop logs are removed in early November and replaced in mid-March and mid-May of the following year. It is intended to remove an additional log in October and increase the present drawdown by 0.3 m. This log will be replaced in mid-April.

3.2 - Steephill Falls Power Development

The drainage area at Steephill Falls is about 85% of the Magpie River basin area and results in a mean annual runoff of about 23 m^3/s. A 30-m high impervious core fill dam will be constructed just upstream from the existing buttress dam, as shown in Figure 6. The new dam will impound a 25-km long reservoir with a surface area of 21.5 km^2 at full supply level. The annual drawdown will be 6.5 m, resulting in an available live storage of about 100 Mm^3 compared to a mean annual inflow volume of about 730 Mm^3. Therefore, the Steephill Falls Reservoir will only permit seasonal regulation of the natural inflows.

Flood flows will be discharged by a double-gated spillway structure constructed on the west abutment of the dam. This structure is designed to accommodate the probable maximum flood without overtopping the core of the dam.

The intake structure for the power development is located on the east abutment of the dam. A 200-m long, 3.5-m diameter penstock will convey power flow to a powerhouse located downstream from the falls and adjacent to the remains of the old powerhouse. The new powerhouse will contain a vertical Kaplan unit with an installed capacity of 15 MW, capable of operating at small gate openings. The installation is designed to maximize energy generation at a plant factor of 50%.

3.3 - Magpie Falls Power Development

The Magpie Falls is located about 3 km upstream from the confluence with the Michipicoten River and about 25 km downstream from Steephill Falls. At this point, the Magpie River forms a cataract with a drop of about 25 m and provides a significant local tourist attraction. The Magpie Falls power development includes the construction of a 3.5-m high overflow weir, as shown in Figure 7, which will be aesthetically designed to blend in with the natural surroundings. The weir will create a small head pond with a surface area of 2.5 km^2. Daily regulation will be permitted at a maximum drawdown of 0.3 m. A small gate will be constructed on the west abutment of the weir to allow for a minimum continuous flow of 7.1 m^3/s to the falls during the daylight period of the tourist season.

A short open channel section will convey power flow to an intake structure, located on the west side of the river. A 150-m long penstock, similar to the Steephill Falls arrangement, will convey power flows to a powerhouse located about 300 m downstream from the falls. The powerhouse will contain the same generating unit as for Steephill Falls but with an installed capacity of 12.5 MW. The entire power development will not be visible from the tourist area.

3.4 - Mission Falls Power Development

The Mission Falls is located just upstream from the confluence with the Michipicoten River and comprises three small natural waterfalls. These falls do not have the same tourist value as the Magpie Falls and a special aesthetic design for the weir is not required. The layout of the power development is quite similar to the one at Magpie Falls, as shown in Figure 8. A 2-m high overflow weir will be constructed just upstream from the falls and a small gate will permit a continuous 24-h/d flow of 4.1 m^3/s over the falls during the tourist season. The weir will create a head pond with a surface area of 0.16 km^2. A drawdown of 0.9 m will permit daily flow regulation only. Power flow conveyance is achieved by an approach channel, intake structure and a 250-m long penstock, leading to a powerhouse located at Fenlon's Lagoon, a small pond off the Michipicoten River. The powerhouse contains a single Kaplan unit similar to Steephill and Magpie falls but with an installed capacity of 15.5 MW.

4 - ENVIRONMENTAL ASSESSMENT STUDIES

Consistent with the guidelines for undertaking EA studies in Ontario, GLP decided to simultaneously carry out further engineering studies, including field investigations, project layout studies and plant operation analyses.

The EA studies of the Magpie River Development started in November 1985, with a meeting attended by representatives of the government agencies that play a role in the EA process. During the EA studies, four such meetings were held.

In January 1986, the first public meeting was held. Because of the bilingual population in the project area, meetings were held in Wawa for the English-speaking population, and in nearby Dubreuilville for the French-speaking population. During the course of the EA process, a total of five such public meetings were held--three of these by GLP and another two initiated by the government.

The purposes of the first, both public and interagency, meetings were

- to introduce the Magpie River project, and
- to obtain feedback on potential environmental impacts resulting from project implementation.

In addition to the first public meetings, several information meetings were held with local government and with special interest groups.

All of these meetings stimulated the expected interest in the project and resulted in a comprehensive list of environmental issues.

Major environmental concerns that formed part of the impact statements were

- plant operations and river flow variations
- the location of a control weir near the brink of the Magpie Falls
- the amount and timing of compensation flow over Magpie and Mission falls
- adverse effects on water quality by inundation of the fume kill area within the Steephill Falls reservoir

- the extent of Steephill Falls reservoir drawdown
- the impact on fish habitat within the Magpie River basin
- increased regulation of Esnagi Lake levels
- native issues.

A large number of less significant issues were also identified. To address all of the concerns adequately, an environmental study program was developed and issued to government agencies and the public for comments. Subsequently, public and interagency meetings were held to describe and explain environmental and engineering study aspects of the program.

The studies were undertaken throughout 1986. At the request of the Township of Michipicoten, an Environmental Monitoring Committee was established consisting of council members and citizens. In addition, newspaper updates were published to keep the public informed of study progress.

A draft Environmental Assessment Report, containing the preliminary results of the study, was prepared in late fall, and was distributed to each government agency and the public for review and comment. Simultaneously, meetings were held to discuss study results.

Generally, the makeup of the EA draft document followed the requirements of the Act. Some nine study components were reported, as follows

- alternatives assessment
- hydrology and water quality
- fisheries
- wildlife and botanical
- geology and soils
- heritage resources
- socioeconomics
- tourism and recreation
- public and government interaction.

Where required, the components existing conditions along the entire river were determined from field studies, and the impact of the project on these conditions was estimated. Mitigation measures were identified for adverse impacts. Residual impacts were documented.

After receipt of written comments from each agency, public interest groups and the public at large, the final EA document was produced in November 1986. It comprises five volumes of material, detailing the entire EA process, study results and recommendations.

In March 1987, MOE officially declared that the project would not be designated under the EA Act and that approval would be granted subject to certain Crown Conditions, to be established by the government in consultation with GLP and the public. For this purpose, further public meetings were held in March 1987 and, at the same time, discussions were started between Government agencies and GLP. This process was completed in late May 1987, and official Government approval for start of construction was given in early June 1987. The approval included about 175 conditions for construction and operation of the project. It is noted that some 120 permits still need to be obtained under various pieces of provincial and federal legislation in order to carry out the construction works.

5 - ENGINEERING STUDIES

To facilitate the preparation of the EA, engineering and environmental studies were carried out simultaneously and an integrated approach to decision making was adopted. This approach resulted in trade-offs between economic and environmental aspects. Particular examples in this respect were the selection of the type and number of generating units and the location and design of the weir at the brink of Magpie Falls. These cases are discussed below.

5.1 - Selection of Generating Units

Past experience with small, low-head, hydro developments has shown that the cost of the electromechanical equipment is often about half of the total construction cost, warranting a careful selection of the generating equipment. The Magpie River Development is no exception to this trend. A number of major environmental constraints, caused by sensitive fisheries habitat upstream and downstream from the power plants resulted in the need to operate all units at small gate openings (less than 15% for single units) for extended periods of time. The unit selection was further complicated by the existence of three different power sites, each with different flow and head.

This somewhat unique situation was not immediately obvious during the early study phases. At that time, capacity and head ranges were anticipated to be smaller, and horizontal Francis units were considered to be the most economical choice. As project layout requirements and hydraulic information became more refined, the need to reexamine all available options became apparent. Thus the main objective became minimizing equipment cost within the environmental requirements and constraints. It was then realized that commonality of design for all three powerhouses would be a prerequisite to achieve this objective.

5.2 - Evaluation of Alternatives

The basic parameters for rating of the units at the three power sites are rated flows ranging from 42 to 47 m^3/s and net heads ranging from 30 to 42 m. Under these conditions, some equipment options usually available for small hydro were not given serious consideration. Bulb and pit units have no technical or financial advantage as such units are generally suited for heads under 10 m. Crossflow or Ossburger units are supplied in much smaller capacities and were not considered further. The 'S' or 'Tube' type units are not recommended for these specific heads and capacities. The turbine efficiency for these units is also somewhat lower due to the relatively high velocities in the water passages. Impulse turbines (Pelton and Turgo) are usually not considered to be economic for the specified head range due to low speeds, resulting in higher generator and overall powerhouse costs.

A reevaluation of the horizontal Francis unit arrangement showed this option to be less economic than the vertical arrangement, as a result of the increased capacity range. Therefore, the alternatives were limited to Kaplan, propeller or vertical Francis units.

Consideration was then given to 'standard' designs. These designs are listed in published catalogs, together with key parameters and dimensions, and are produced by manufacturers to provide economically priced equipment for small hydro developments. It was found that only Francis units of 6- to 8-MW capacity range, suitable for the two-unit option, were generally available in 'standard' designs.

Manufacturers also have many designs available that can be customized to suit the specific needs of a project, at a small additional cost. While such units are more economical than newly designed units, it is important to verify that the performance guarantees provided by the supplier can be met. This is established from model tests and/or actual field test data for units that are nearly homologous, i.e., units with some deviations from the homologous design, which usually can be readily evaluated.

Based on information received from suppliers, and after comparison studies of the selected alternatives, including the evaluation of factors such as unit efficiency, outages and schedule, it was concluded that a single Kaplan unit for each power site would provide the most economical alternative for the Magpie River Development.

5.3 - Detailed Considerations

The main factor in favor of the Kaplan unit is its much better performance at outputs below 50%, compared to the Francis and propeller units. Due to environmental conditions, the units are required to operate at outputs less than 15% of rated capacity for extended periods of time. From actual experience with similar units it was determined that such operation would be possible, and this was confirmed by competitive tenderers.

The relative difference in performance among the Kaplan, propeller and Francis units is indicated in Figure 9. The difference in performance between the lowest cost options of single Kaplan and double Francis units is shown in Figure 10. An alternative option of providing one smaller and one larger unit per site, similar to an existing development in Norway, was not deemed to offer any cost advantage as this would require two different designs in one powerhouse. This would result in higher engineering and construction cost, in addition to the higher equipment cost, and the need for two sets of spare parts, draft tube stop logs, etc.

For the two units per site option, it was established that extra equipment cost and construction and engineering cost would be needed, compared to the single unit option. For example, two additional major items are required--a bifurcation in the penstock and unit isolating valves at the spiral casing inlet.

Based on preliminary data received from interested suppliers, it became obvious that the combined cost for all three sites would be lowest if the same size turbine was used. For the generator and other electrical equipment, it appeared to be economical to design this equipment for the specific power ratings at each site.

These assumptions were confirmed after tenders for the main equipment had been evaluated. The three lowest tenderers offered units which were identical for all three sites and had the same speed. This commonality of design proved to be most economical and only presented a few anomalies, such as the fact that the turbine is basically too large for the highest head plant at Steephill Falls. This was resolved by restricting the gate opening to match the generator output limitations.

The successful bid has a Kaplan unit with seven blades. This unit is expected to give excellent performance down to around 10% output.

It is worthwhile to note that the selection of two Kaplan units at each site would have further benefits as continuous operation would be possible without significant loss of efficiency. However, this would also have resulted in uneconomic capital cost increases.

5.3.1 - Location and Design of the Weir at Magpie Falls

Magpie Falls is a primary tourist attraction in the Wawa area. It was recognized at the outset that construction of a weir at the brink of the Magpie Falls would be a sensitive environmental issue. Studies were, therefore, undertaken to preserve and enhance the Magpie Falls tourist area. Considerations included

- alternative project layouts and weir locations
- provision of compensation flow during the tourist season
- aesthetically compatible weir design
- development of a tourist-oriented master plan for the Magpie Falls area.

Details of these studies are provided below.

5.3.2 - Alternative Project Layouts and Weir Locations

The brink of Magpie Falls consists of stepped sections of exposed bedrock over a length of about 50 m directly upstream from the vertical drop which comprises the actual falls (Figure 11). A weir at this location would, therefore, be founded on bedrock and would be about 90 m long.

Upstream from this area, the bedrock drops steeply to a depth of about 25 m or more at a point, some 300 to 400 m upstream. At this location, the river is wider and bedrock is overlain by fine sand and clayey silt layers. A weir at this location cannot be built on bedrock. However, it would be possible to achieve a satisfactory engineering design at this location at a significant increase in cost.

Among other main factors, such as the type of power flow conveyance and the location of the powerhouse, the economics of the project layout is significantly affected by the location of the weir. Three project layouts were considered as follows.

- Alternative A: A weir located at the brink of the Magpie Falls with a short open canal excavation at the west bank to convey flow to an intake structure and a penstock leading to a powerhouse located just downstream from the gorge below Magpie Falls. Comparative cost: base case.

- Alternative B: A small dam located about 400 m upstream from the brink of the Magpie Falls with a visible open canal on the west bank, parallel to the river and leading to an intake structure, penstock and powerhouse, similar to the alternative above. Comparative cost: base case plus $2.3 million (1986 dollars).
- Alternative C: A small dam located about 400 m upstream from the brink of Magpie Falls with an intake and power tunnel on the east bank leading to a powerhouse opposite to the powerhouse location under the above alternatives. Comparative cost: base case plus $3.0 million (1986 dollars).

The first alternative was selected. In this layout concept, the open canal and intake structure are hidden from view in the east bank tourist area by maintaining a treed area between the river and the canal.

5.3.3 - Compensation Flows

The minimum flow that would maintain the aesthetic integrity of the falls was assessed to be 7.1 m^3/s. This flow maintains the basic beauty of the falls and is similar to flows shown in tourist information material prepared by the local Chamber of Commerce. Under natural conditions, the flow over the falls varies considerably, reaching a low of 1.8 m^3/s. After project implementation, a continuous flow of 7.1 m^3/s will be retained for 14 h/d from May to October, even during periods when natural flows would have been lower. This could be viewed as a net benefit.

The proposed compensation flow represents 7% of the available flow in the river and amounts to an equivalent present value in lost power generation in excess of $4.0 million (1986 dollars).

5.3.4 - Aesthetically Compatible Weir Design

The weir will be located about 50 m upstream from the vertical drop of the Magpie Falls. To reduce environmental concerns, the weir is designed to blend in with its natural surroundings, as shown in Figure 12. It will be double crested with uniform flow distribution over the lower weir crest. Flow control will be achieved by means of a gate, hidden from view.

Angular rock will be lodged in the apron of the weir to naturalize the appearance of the weir, creating rippling effects and turbulence to emulate the natural approach to the falls. Native stones will be used throughout the apron of the weir and vegetated promontories will be retained at both ends of the weir to reduce the impact of the weir length.

The estimated cost increase of providing the weir with a double crest, gated flow control and uniform flow distribution is about $250,000 (1986 dollars).

5.3.5 - Tourist-Oriented Master Plan

The last element of environmental mitigation was the introduction of a master plan for development of the Magpie tourist area. The plan was proposed in three phases and funding for Phase 1 will be carried by GLP. Phase 1 includes the following components

- improvements to the entrance from Highway 17, access and parking
- improved viewing facilities of the falls and gorge
- development of a display area
- development of a Magpie Lake recreation area
- trails.

The plan emphasizes the pristine quality of the falls while proposing an arrangement of facilities which will encourage increasing numbers of visitors to stay for longer periods of time. The estimated cost of Phase 1 of the plan is $350,000 (1986 dollars).

6 - REVIEW

As demonstrated in the previous sections, the EA process clearly has a significant effect on the engineering and economic aspects of project development. While the review process carried out for the Magpie River Development was not entirely typical of the formal process, the studies undertaken were consistent with the requirements of the Act. The experience obtained is therefore representative and valuable with regard to planning of future projects of this nature.

6.1 - Study Schedule

The EA process provides for the integrated planning of the multiple use of available natural resources. To this end the planning process involves exchanges among the public, the government and the proponent. The public can be represented by various clubs, organizations, interest groups, individuals, etc. Government includes ministries or other representatives at the federal, provincial and municipal level. In the Magpie case, a total of about 20 actively contributing groups were involved in the assessment process. Such extensive participation is very time consuming.

Therefore, to maintain the usually tight study and construction schedule it is necessary to start the environmental assessment studies as early as possible, preferably during the early engineering and economic planning stages.

As major environmental impacts will be identified at the early stage of the planning process, an estimate of the extent of likely mitigation can be made. Alternatively, if an unsurmountable problem occurs, the project can be abandoned after appropriate consultation. In either case, the financial risk to the proponent will be minimized.

6.2 - Study Coordination

As noted above in the EA process, multidisciplinary aspects are addressed simultaneously with careful monitoring by a large number of groups. It is inevitable that disagreements about the issues will occur and judgments will have to be made as scientific or exact solutions are not always available.

Within this planning environment trade-offs between engineering, economic and environmental aspects have to be made. Acceptable solutions to the issues involved can only be achieved by frequent discussions between the parties.

This approach was followed during the Magpie EA studies and, although cumbersome, was generally found to contribute to establishing satisfactory compromises in the use of the resources.

Final approval of the Magpie project was based on the conclusions and recommendations of the EA report, supplemented by about 175 Crown Conditions and third-party commitments. To undertake the construction works GLP must obtain some 120 permits in addition to preparing construction monitoring reports. Clearly, these conditions, permits and reports, supplemented by regular inspection of the construction sites by MOE and MNR staff, will ensure adherence to the proposed environmental mitigation measures during and after construction.

6.3 - Extent of Impacts

In the early stages of the EA process for the Magpie River Development, some eight major issues and a large number of minor issues were identified. Initially, the major issues appeared to be of a serious nature, jeopardizing the viability of the entire project. However, as studies and field investigations progressed, solutions were found, suitable mitigation measures were introduced and, in one case, the issue was found not to be a problem, once it was quantified. This case involved the possible contamination of the proposed main Steephill reservoir and its outflows with toxic metals from inundating part of the fume kill area, located north of Wawa. This area developed as a result of emissions from a local sintering plant, and the initial fear was that soils were laden with metals. Field and laboratory analyses showed that, because of the extremely porous nature of the soils, any accumulated materials had already been leached from the system. Concentrations of target parameters in the future water body were therefore predicted to be within provincial guidelines.

All of the major and minor environmental concerns were ultimately accommodated by mitigation measures. The residual impacts were reduced to an acceptable level and project approval was obtained. The lesson learned is that even apparently insoluble problems could be resolved through the integrated efforts of the engineering, economic and environmental disciplines.

FIGURES

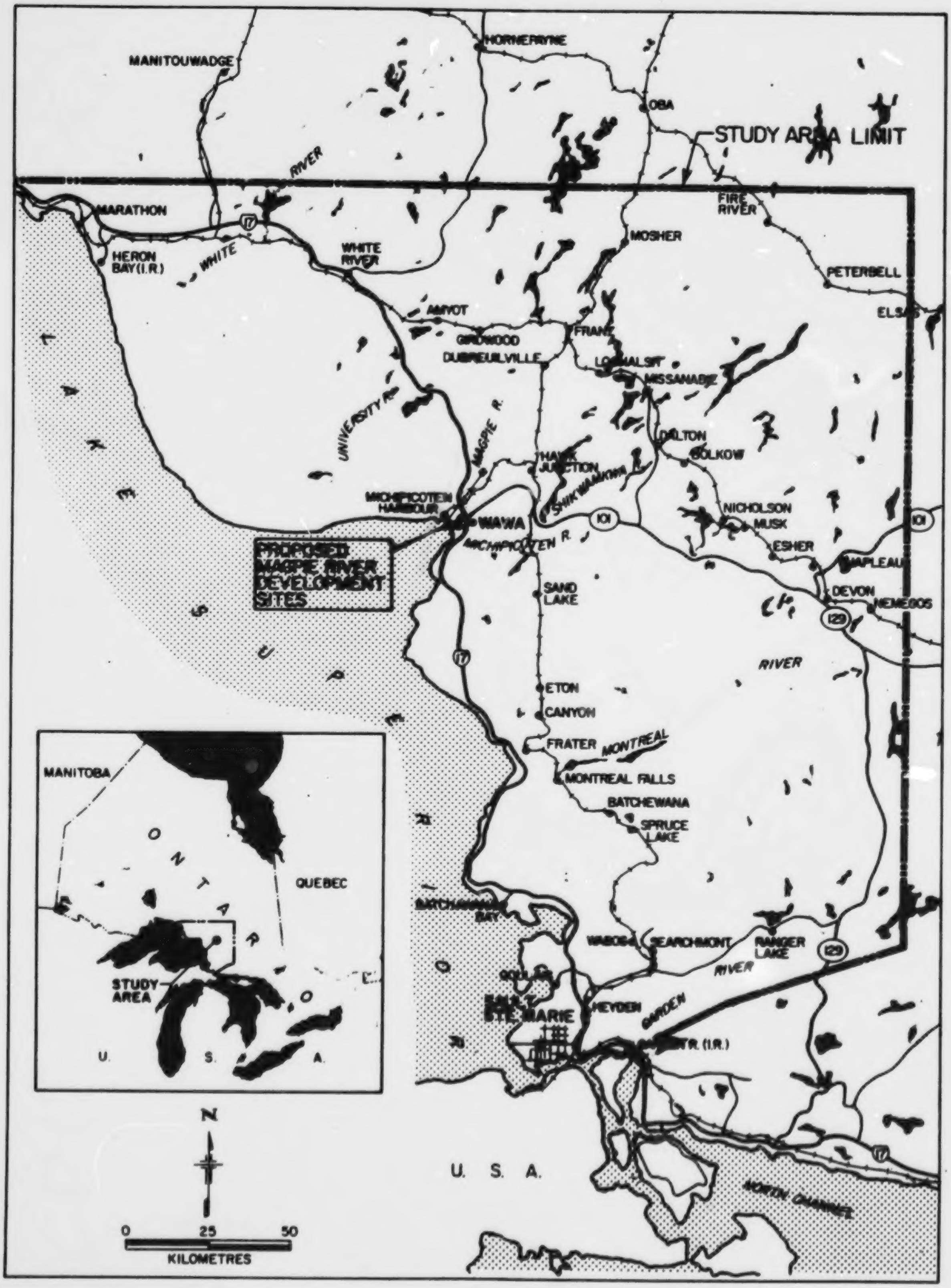
MANITOUWADGE
HORNEPAYNE
OBA
STUDY AREA LIMIT
RIVER
WHITE
MARATHON
17
HERON BAY (I.R.)
WHITE
WHITE RIVER
FIRE RIVER
MOSHER
PETERBELL
AMYOT
GIRDWOOD
DUBREUILVILLE
FRANZ
LOCHALSH
MISSANABIE
UNIVERSITY R.
MAGPIE R.
DALTON
BOLKOW
HAWK JUNCTION
SHIKWAMKWA
MICHIPICOTEN HARBOUR
WAWA
101
NICHOLSON
MUSK
ESHER
CHAPLEAU
DEVON
NEMEGOS
101
MICHIPICOTEN R.
PROPOSED MAGPIE RIVER DEVELOPMENT SITES
SAND LAKE
129
L A K E
S U P E R I O R
RIVER
17
ETON
CANYON
FRATER
MONTREAL
MONTREAL FALLS
BATCHEWANA
SPRUCE LAKE
BATCHAWANA BAY
WABOS
SEARCHMONT
RANGER LAKE
RIVER
129
GOULAIS
SAULT STE. MARIE
HEYDEN
GARDEN
GARDEN R. (I.R.)
17
U. S. A.
NORTH CHANNEL
MANITOBA
ONTARIO
QUEBEC
STUDY AREA
U. S. A.
N
0
25
50
KILOMETRES

FIG. I

MAGPIE RIVER DEVELOPMENT

GENERAL STUDY AREA

ACRES

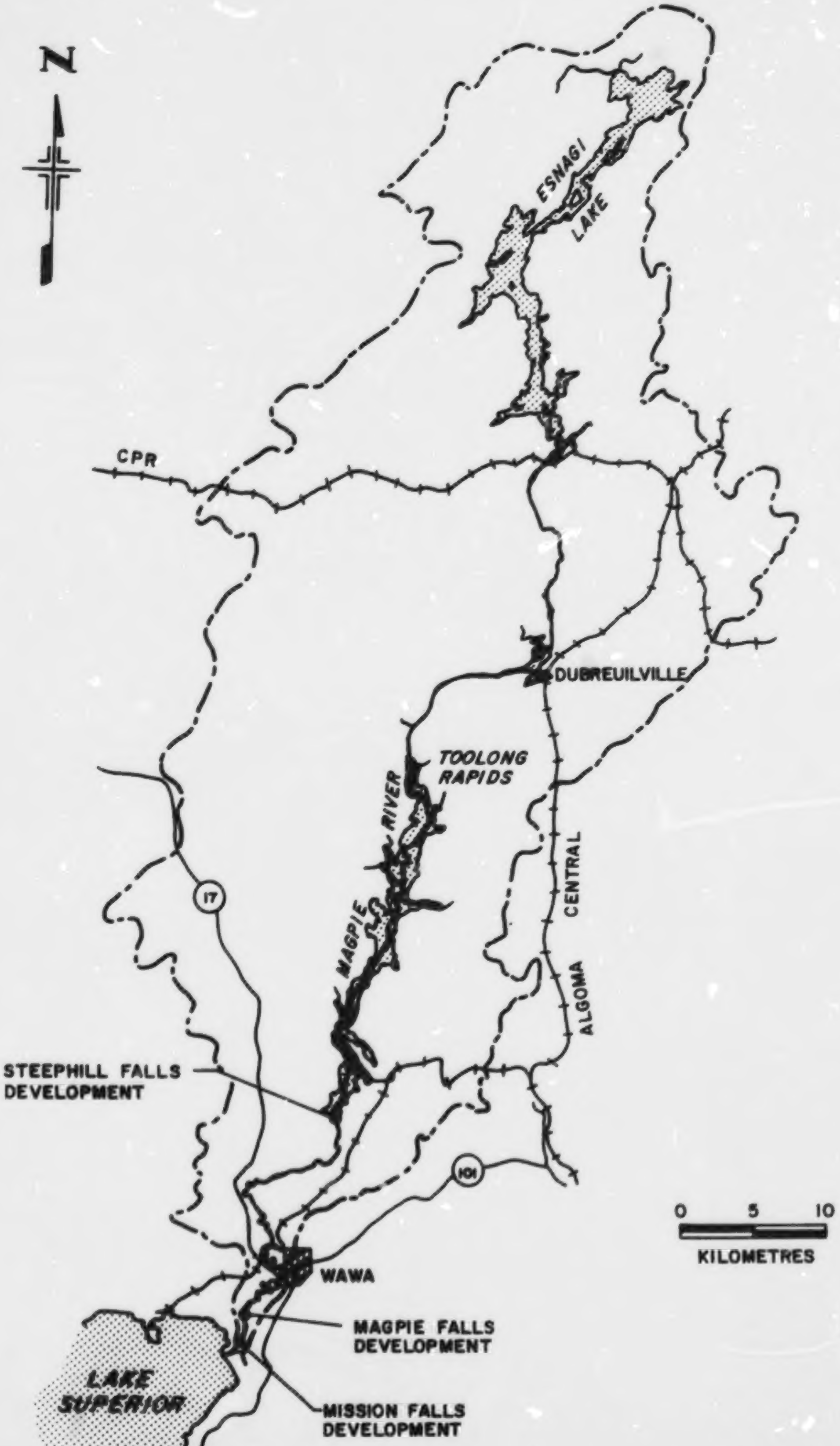
N
ESNAGI LAKE
CPR
DUBREUILVILLE
TOOLONG RAPIDS
MAGPIE RIVER
ALGOMA CENTRAL
17
STEEPHILL FALLS DEVELOPMENT
101
0 5 10
KILOMETRES
WAWA
MAGPIE FALLS DEVELOPMENT
LAKE SUPERIOR
MISSION FALLS DEVELOPMENT

FIG. 2

MAGPIE RIVER DEVELOPMENT

MAGPIE RIVER DRAINAGE BASIN

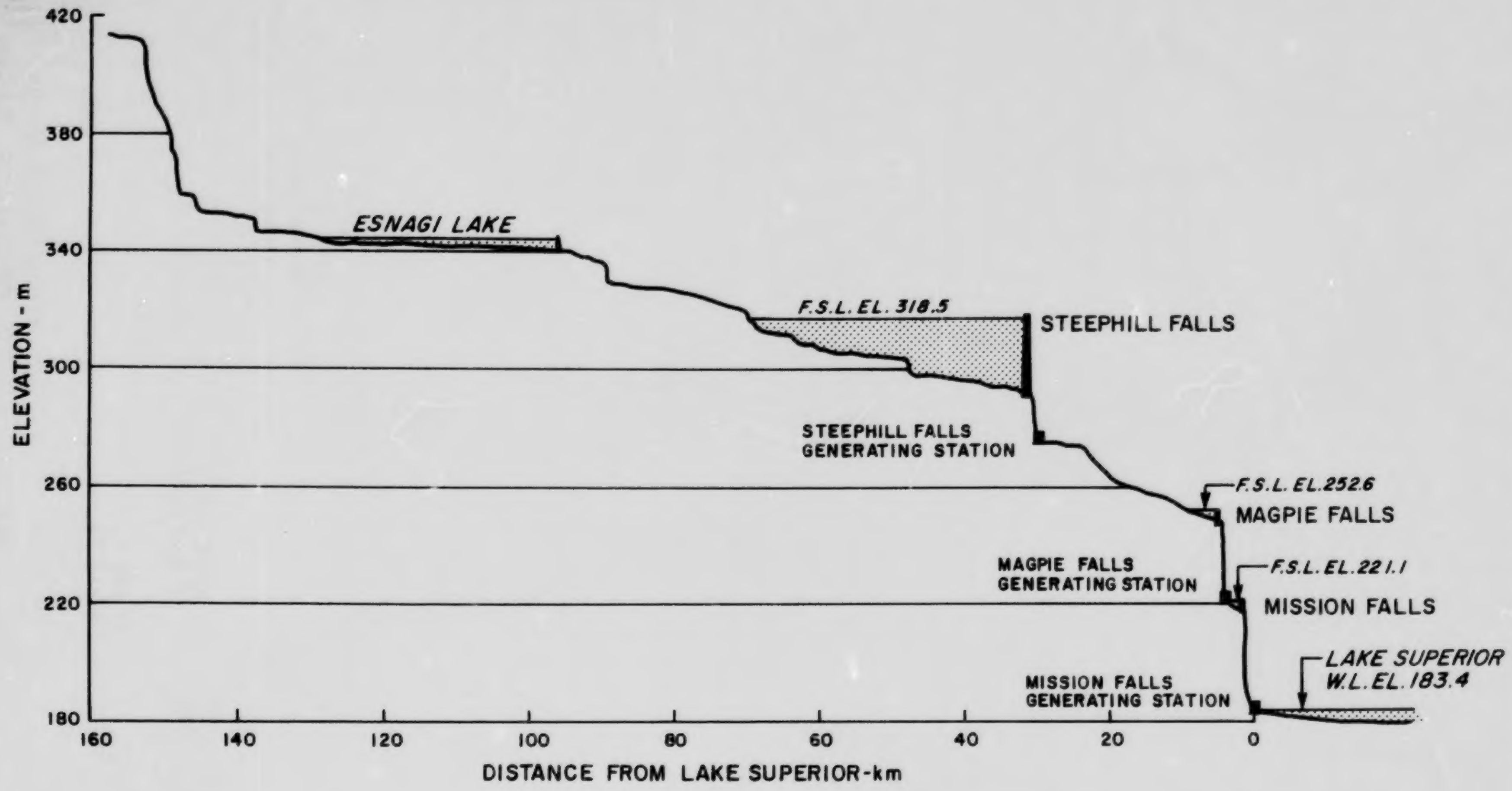

FIG. 3

MAGPIE RIVER DEVELOPMENT

PROFILE OF MAGPIE RIVER

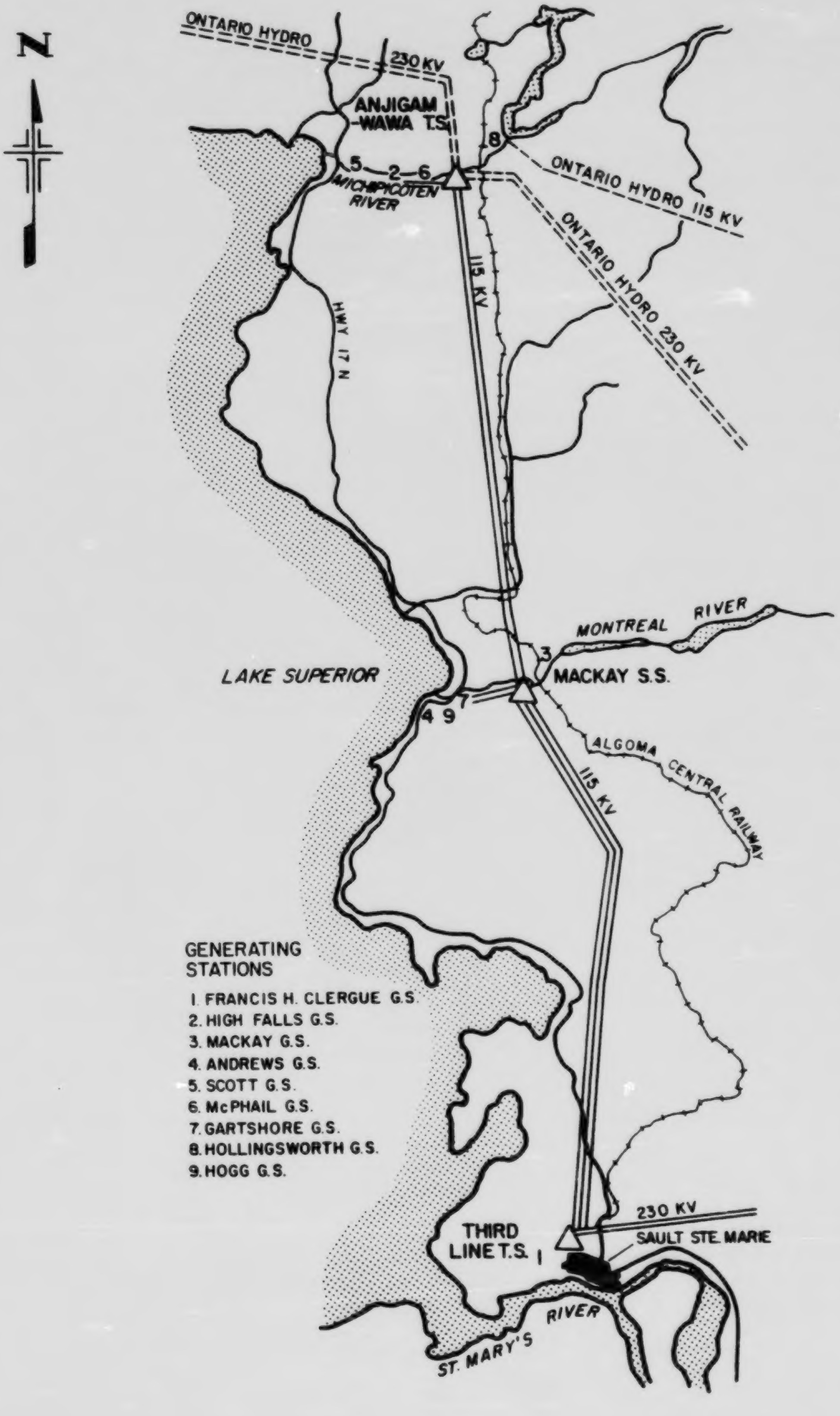
N
ONTARIO HYDRO
230 KV
ANJIGAM -WAWA T.S.
8
5
2
6
MICHIPICOTEN RIVER
ONTARIO HYDRO 115 KV
ONTARIO HYDRO 230 KV
115 KV
HWY 17 N
MONTREAL RIVER
3
LAKE SUPERIOR
MACKAY S.S.
7
4 9
ALGOMA CENTRAL RAILWAY
115 KV
GENERATING STATIONS
1. FRANCIS H. CLERGUE G.S.
2. HIGH FALLS G.S.
3. MACKAY G.S.
4. ANDREWS G.S.
5. SCOTT G.S.
6. McPHAIL G.S.
7. GARTSHORE G.S.
8. HOLLINGSWORTH G.S.
9. HOGG G.S.
230 KV
THIRD LINE T.S.
1
SAULT STE. MARIE
ST. MARY'S RIVER

FIG. 4

MAGPIE RIVER DEVELOPMENT

EXISTING GREAT LAKES POWER SYSTEM

ENVIRONMENTAL ASSESSMENT

Formal Assessment Under the Environmental Assessment Act of Ontario	**Great Lakes Power Limited to Perform Environmental Assessment Study**
Presubmission consultation with agencies and public strongly advised but not legal requirement	*GLP will undertake presubmission consultation with agencies and public* *- Public meeting in January, April and September/October 1986* *- Interagency meetings in November 85, March, September/October 1986* *- Additional meetings as required*
Evaluation of alternatives to the project	*GLP will evaluate alternatives to the project* *- GLP has issued report "Assessment of alternatives to the Magpie River Development" in March 1986 to* *• Min of Transportation and Communications, Downsview* *• Min of Municipal Affairs, Toronto* *• Min of Natural Resources, Toronto* *• Min of Energy, Toronto* *• Min of Environment, EA Board, Toronto* *• Min of Tourism and Recreation, Toronto* *• Min of Citizenship and Culture, Toronto* *• Min of Natural Resources, Sudbury* *• Min of Environment, Sudbury* *• Min of Northern Dev and Mines, Sault Ste. Marie* *• Min of Natural Resources, Wawa* *• Department of Indian and Northern Affairs*
Evaluation of alternative methods of developing project	*GLP will evaluate alternative methods of developing the Magpie Project*
EA to assess potential mitigation and predict 'net' effects	*GLP will assess potential mitigation and predict 'net' effects*
Applicant to prepare and submit EA document to MOE for government and public review	*GLP will prepare and submit EA study report to MOE for informal government review* *- GLP will make EA study report available for public review*
MOE prepares government review available to public Public can submit comments and request hearing	*MOE will prepare informal government review available to public for review and comment*
MOE can - accept EA document - approve project or refer to the EA board for a public hearing	*MOE can designate project at any time if unresolved issues remain*
Permits applied for and issued after EA accepted and project approved by MOE	*GLP will use EA study report as support document for permit applications*

FIG 5

MAGPIE RIVER DEVELOPMENT
E A PROCESS

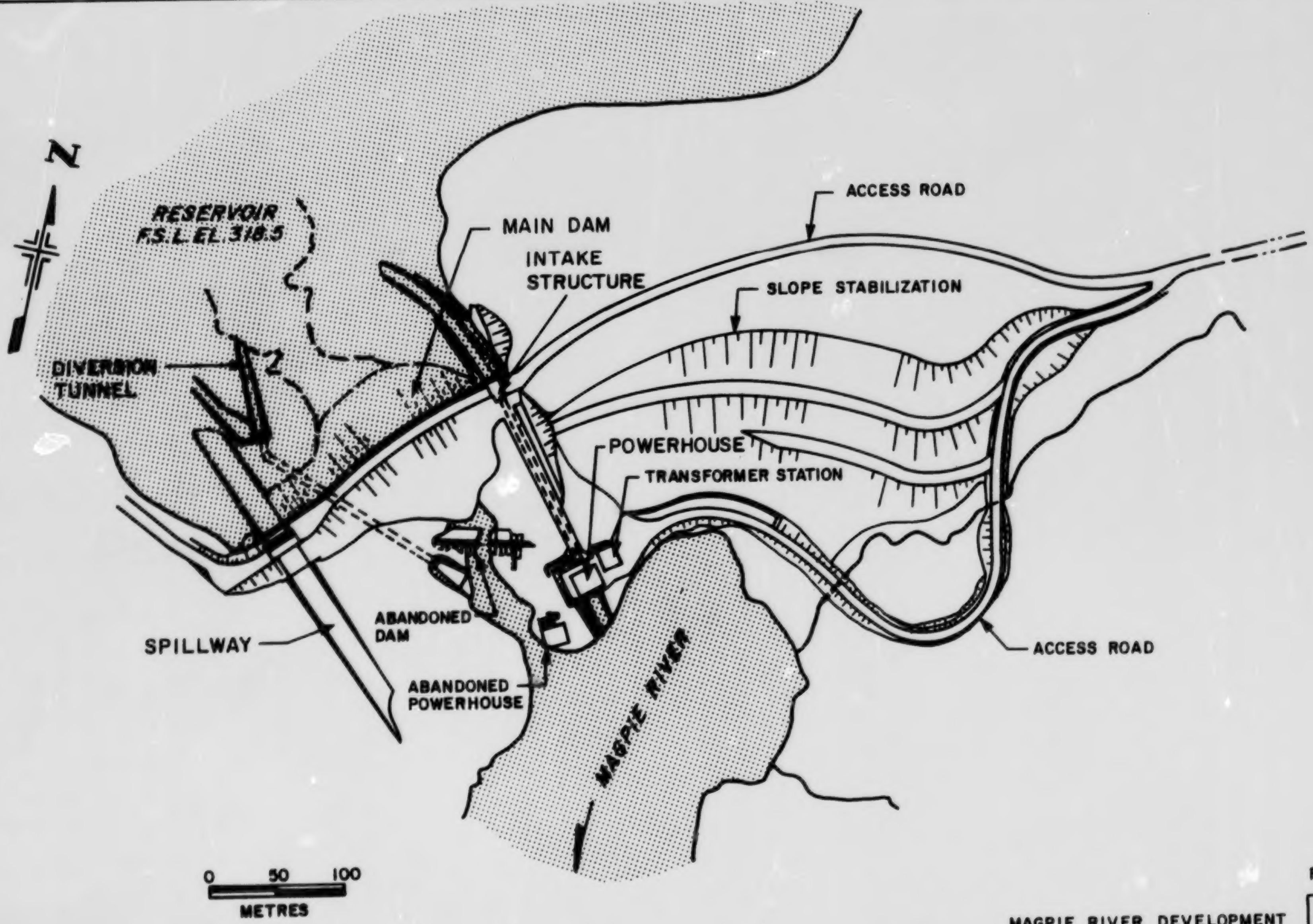
N
RESERVOIR
F.S.L. EL. 318.5
DIVERSION TUNNEL
MAIN DAM
INTAKE STRUCTURE
ACCESS ROAD
SLOPE STABILIZATION
POWERHOUSE
TRANSFORMER STATION
ACCESS ROAD
SPILLWAY
ABANDONED DAM
ABANDONED POWERHOUSE
MAGPIE RIVER
0
50
100
METRES

FIG.6

MAGPIE RIVER DEVELOPMENT

STEEPHILL FALLS SITE LAYOUT

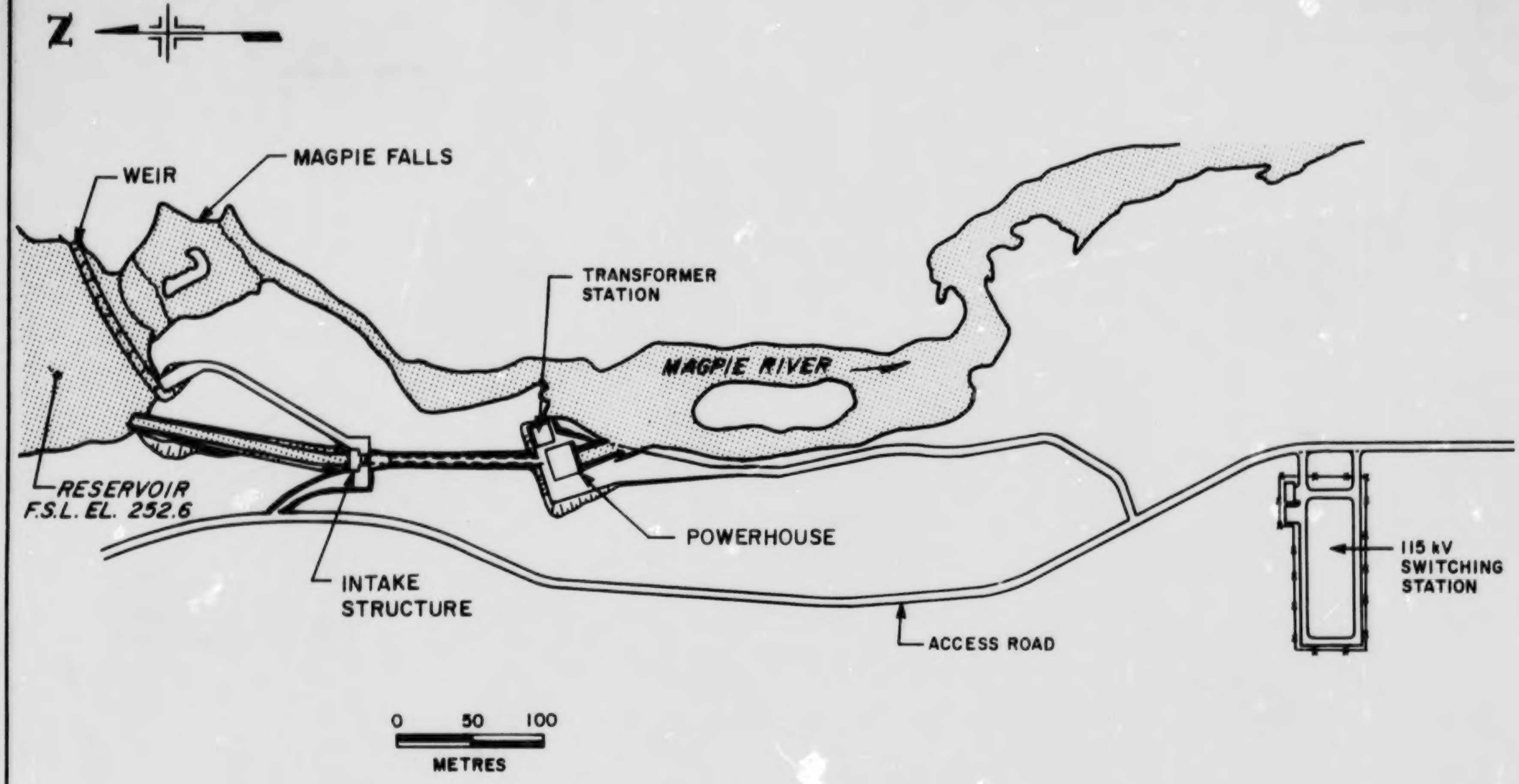
Z
WEIR
MAGPIE FALLS
TRANSFORMER STATION
MAGPIE RIVER
RESERVOIR F.S.L. EL. 252.6
POWERHOUSE
INTAKE STRUCTURE
115 kV SWITCHING STATION
ACCESS ROAD
0 50 100
METRES

FIG. 7

MAGPIE RIVER DEVELOPMENT

MAGPIE FALLS LAYOUT

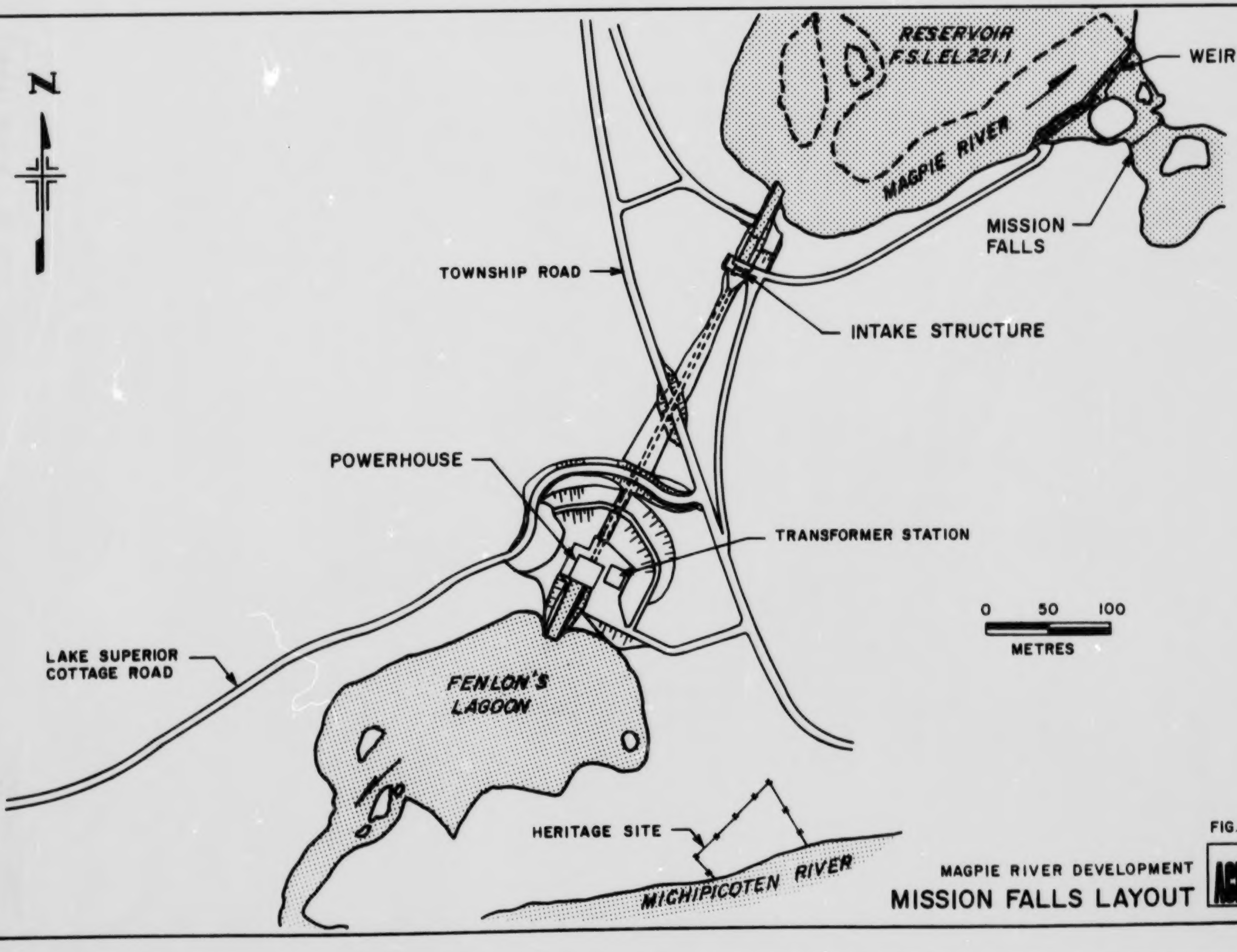
N
RESERVOIR
F.S.L.EL.221.1
WEIR
MAGPIE RIVER
MISSION FALLS
TOWNSHIP ROAD
INTAKE STRUCTURE
POWERHOUSE
TRANSFORMER STATION
0 50 100
METRES
LAKE SUPERIOR COTTAGE ROAD
FENLON'S LAGOON
HERITAGE SITE
MICHIPICOTEN RIVER
ACRES

FIG. 8

MAGPIE RIVER DEVELOPMENT

MISSION FALLS LAYOUT

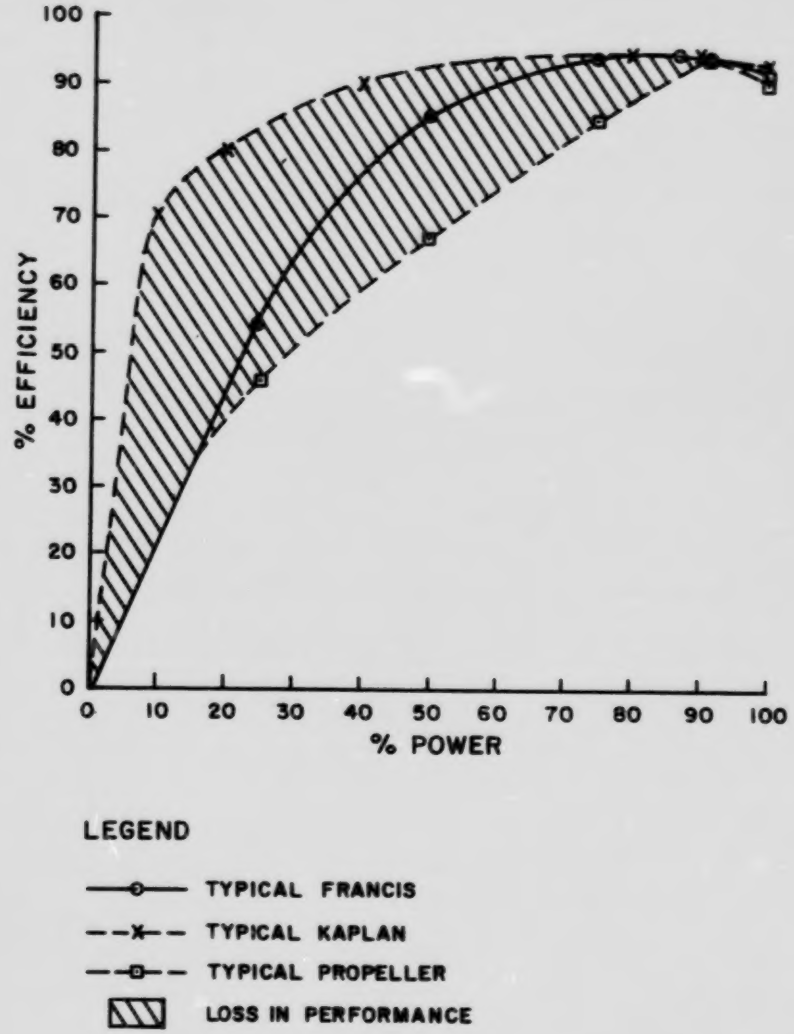

FIG. 9

MAGPIE RIVER DEVELOPMENT

COMPARISON
OF KAPLAN, PROPELLER AND FRANCIS TURBINE EFFICIENCIES

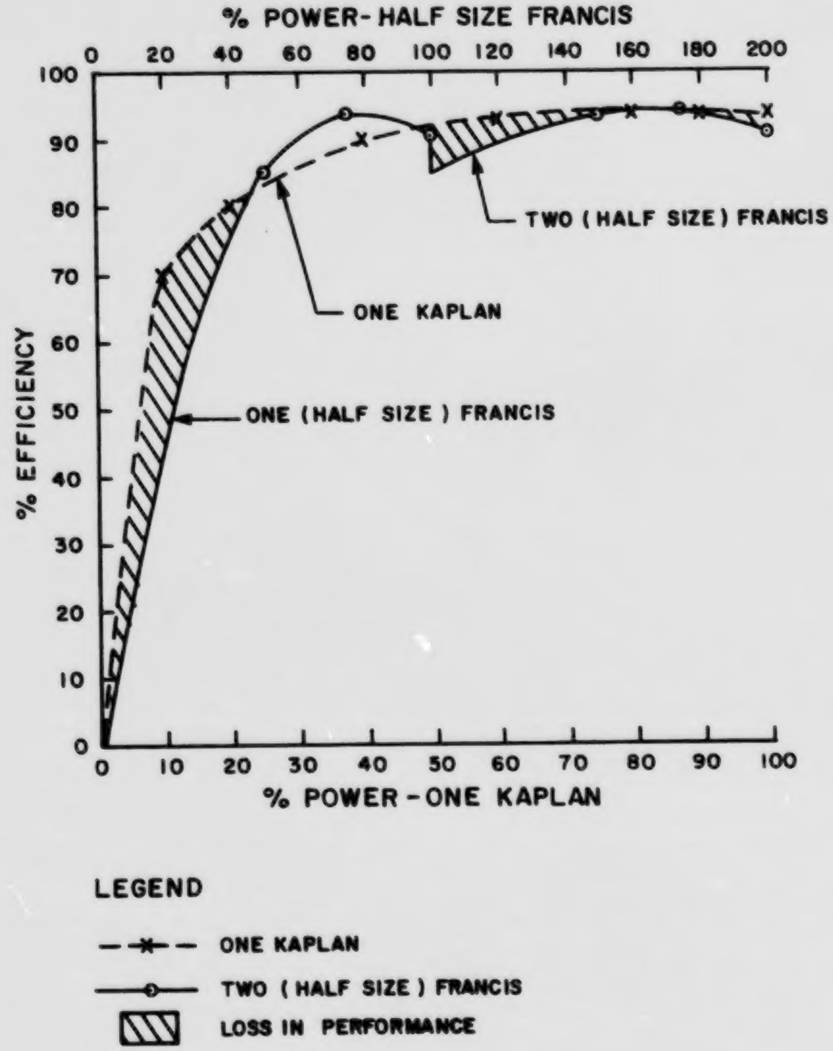

FIG. 10

MAGPIE RIVER DEVELOPMENT

COMPARISON OF EFFICIENCIES OF ONE KAPLAN vs TWO FRANCIS

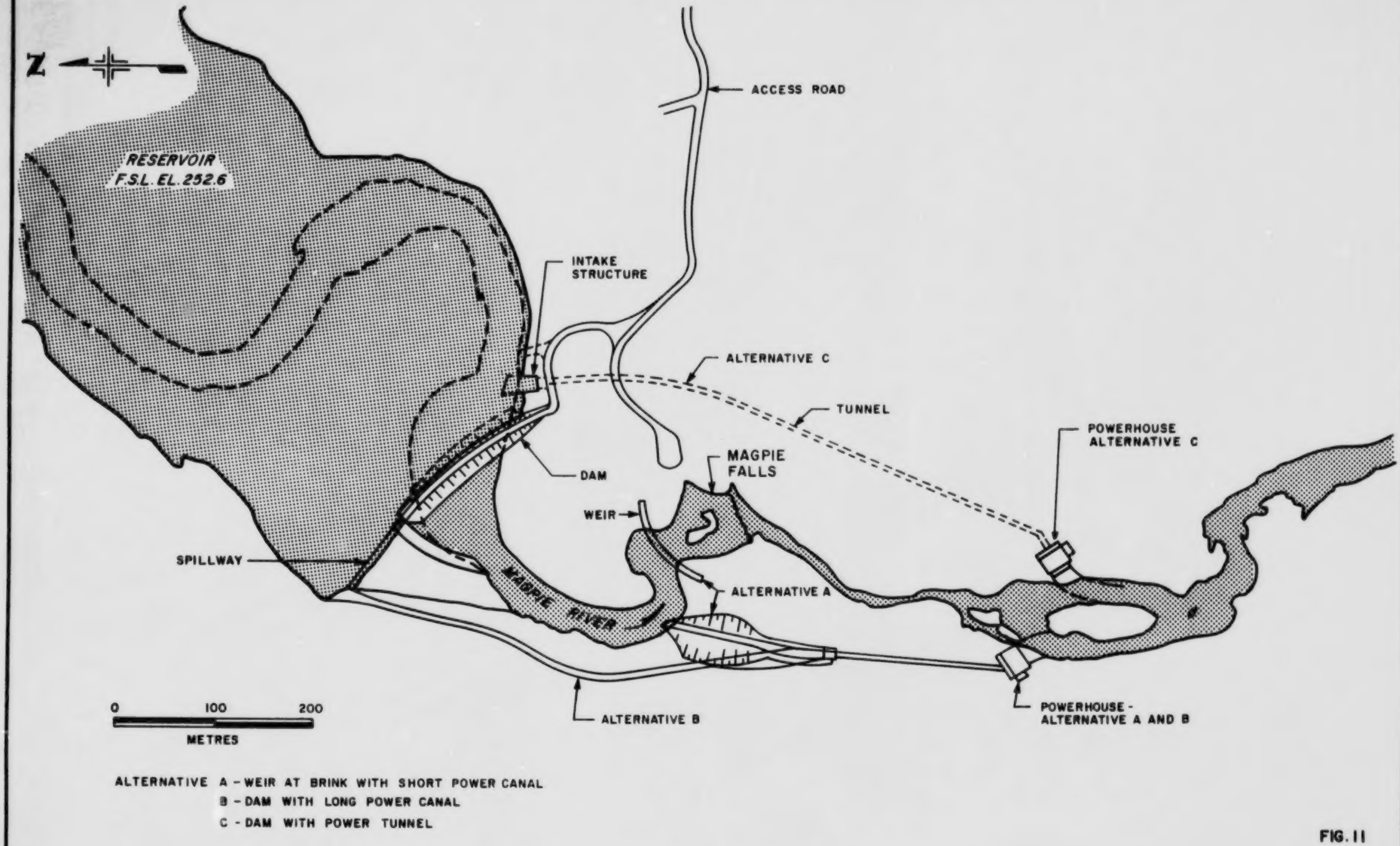
N
RESERVOIR
F.S.L. EL. 252.6
ACCESS ROAD
INTAKE STRUCTURE
ALTERNATIVE C
TUNNEL
POWERHOUSE ALTERNATIVE C
DAM
MAGPIE FALLS
WEIR
SPILLWAY
ALTERNATIVE A
MAGPIE RIVER
0
100
200
METRES
ALTERNATIVE B
POWERHOUSE - ALTERNATIVE A AND B
ALTERNATIVE A - WEIR AT BRINK WITH SHORT POWER CANAL
B - DAM WITH LONG POWER CANAL
C - DAM WITH POWER TUNNEL

FIG. 11

MAGPIE RIVER DEVELOPMENT

MAGPIE FALLS ALTERNATIVE ARRANGEMENTS

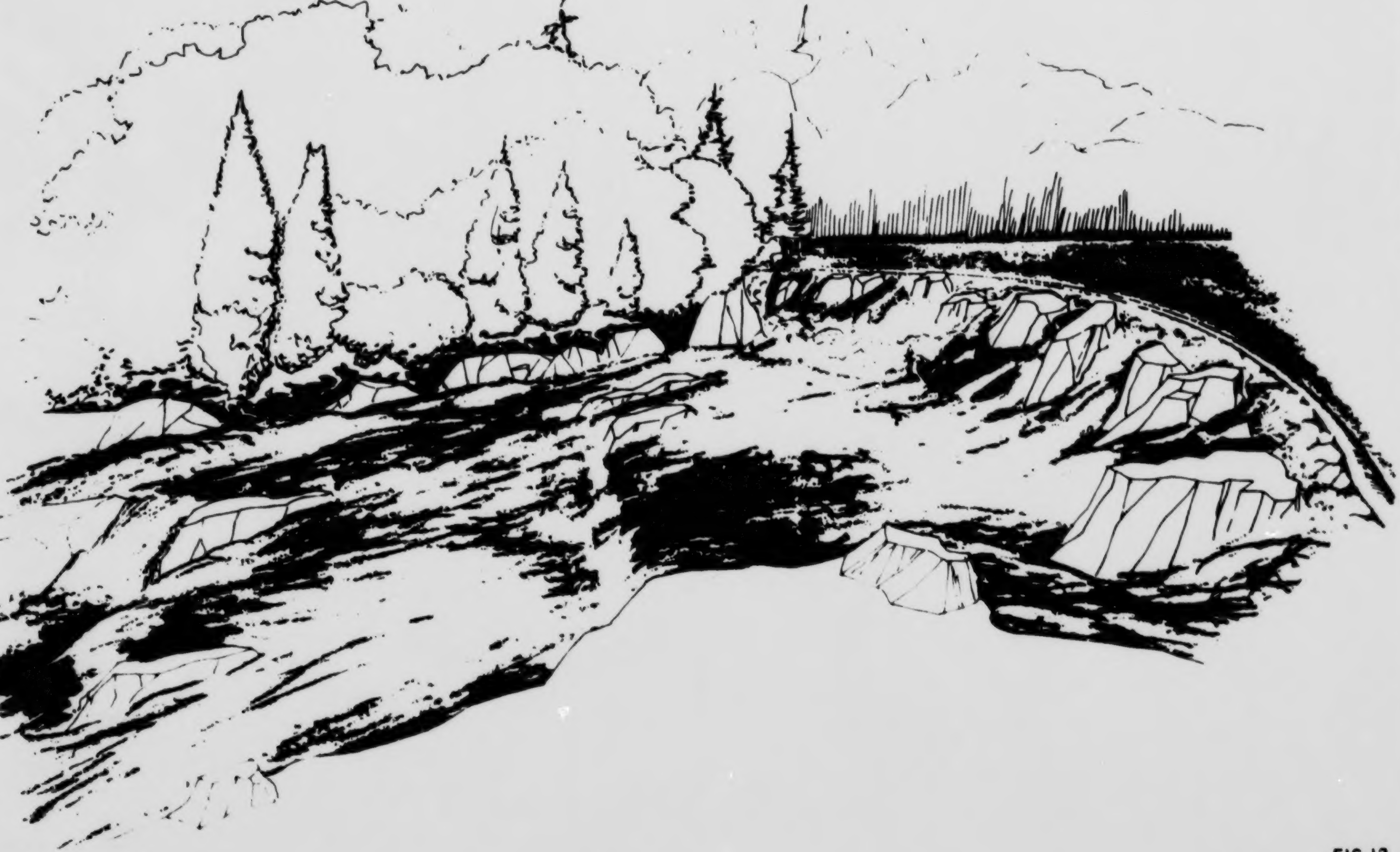

FIG. 12

MAGPIE RIVER DEVELOPMENT

FALLS CREST AND CONTROL WEIR

ACRES

Almonte Generating Station

By
B. Gallagher

44

SMALL HYDRO CONFERENCE

July 15, 1988

Case Study

Almonte Generating Station Rehabilitation

This case study concentrates on three areas of the project:

- History of Plant
- Alternative Methods of Redevelopment
- Construction Activity to The Present

The Town of Almonte is located approximately 350 kilometres north east of Toronto just west of Ottawa. It was named after a Mexican General Almonte in the mid 1800's. Presently the population of the town is 4100 and it has its own Public Utilities Commission which administrates the operation of the existing Almonte Generating Station. As is the case with many communities in Southern Ontario, the Town of Almonte was established on the banks of the Mississippi River because of the large resource of hydraulic energy. At the present time there are 6 mill sites visible on the river within the town.

The Mississippi River drains a watershed of more than 3500 square kilometres before it reaches Almonte. Upstream there is one Ontario Hydro Generating Station as well as three large reservoir lakes, Cross Lake, Gull Lake and Long Lake. These were established at the beginning of the century by the Mississippi River Improvement Company, an organization which represents all of the power producers on the river. Its operations are now located at the Belleville District Office of Ontario Hydro. Regulation of the river flow has been quite effective.

As a result, the flow duration curve for the year is very flat with very dependable low flows and seasonal mean flows which actually increase in the normally dry months of December, January and February - the period when electrical demands for the utility are the highest.

As the technology for hydro electric generation advanced in the early 1900's the community of Almonte developed a small Public Utilites Commission plant near the existing site on the Mississippi River a 75 Kw waterwheel. By 1926 the plant capacity was no longer able to meet the demand of the town and a new powerhouse was built. It was an open flume arrangement with two vertical Francis turbines. The first was commissioned in 1926, it generates approximately 340 kilowatts and the second was installed in 1932, it generates 505.

While the plant originally provided all of the energy required for the community, it now meets only 12 percent of the demand and the P.U.C. purchases the remaining energy required from Ontario Hydro. Consequently, any additional power which could be realized from the site could easily be absorbed. While the existing plant has been very dependable the desire for additional energy as well as the gradually increasing requirement for repairs prompted the utility to contemplate expansion replacement or serious enlargement of the plant. This began in earnest in 1980, when Ontario Hydro was called in to have a preliminary look at the plant. Subsequently the commission obtained a feasibility report as well as proposals from turbine manufacturers (Describe the river in Almonte).

There are four basic ways of expanding the plant. These are best understood if the route of the river through the town is explained. The banks of the river are lined with communities, businesses and homes. The river drops a total of 19 metres within the town and the fall occurs over 3 distinct drops.

The first drop which occurs adjacent to the railway is approximately 3 metres. A further 200 metres downstream, a drop of 9 metres occurs at the existing public utilities commission plant. Downstream of the plant, within the area immediately below the tailrace, there is a further 7 metre head available. In parallel to the town plant with 16 metres of head there is a second mill which is located approximately 300 metres to the north. Flow to this second mill is via the chancery channel, a channel which must have received its name from the early chancery court, a court of equalization. Equalization in this case could mean either equalization of flow or equalization of the forebay elevations to the intakes of the two plants.

The first and most comprehensive alternative was the development of 19.2 meters of head including the purchase of the Almonte Flour Mill adjacent to the railway track, demolition of the existing Public Utilities Commission plant and a construction of a powerhouse in the town park below the existing tailrace. The water passage into the new plant would best be provided by the construction of a 350 metre penstock. Unfortunately the penstock would have to be installed within the main channel of the river and be installed under the chancery channel which provides a minimal flow now for aesthetic reasons to a condominium project and to a private home. In addition to interuppting the passage of flow to the chancery channel, the construction of the penstock would also interfere with high flood flows in the area. The chancery channel modelled at the 100 year flood level floodsadjacent homes. Hence, the penstock would have to be buried in the rock bottom of the river and the concrete encased. A 4.5 megawatt plant would require 2 eight foot diameter penstocks. The estimated cost of this alternative is $10,000,000.

The second alternative is the construction of a new plant adjacent to the millhouse condominium project. This would provide a plant with 16.0 metres of head and construction would be facilitated because the chancery channel could be blocked off, and easily dewatered so the construction could proceed in the dry and the existing powerhouse could provide energy for the duration. Unfortunately, the chancery channel would provides flow in that direction is rather shallow and the passage of old plant flow would prevent the formation of an ice cover during winter. With no ice cover, a significant ice accumulation would probably occur and presently would be a significant problem for operation of a plant. In fact, the accumulation of ice is a serious problem at the existing powerhouse which has an even deeper approach. Construction of a 3.9 megawatt plant millhouse site would cost in the order of $7,000,000.

The third alternative is the combination of the existing town plant with the additional fall available below the tailrace, a plant with 16.2 metres of head could be constructed in this case. The existing plant would be used as an intake, the penstock would pass down the tailrace to the town park and a new powerhouse with 3.2 megawatt-capacity would be constructed. Significant costs of this alternative include protection of the penstock from the erosive forces of high velocity flow since the penstock is directly in the channel and also the repairs to the existing powerhouse structure and intake which would be substantial. The total cost is approximately six million dollars.

The fourth alternative was the rehabilitation of the existing plant. The present units are vertical Francis with 1700 diameter wheels and direct coupled synchronous generaters. Both are installed in open flumes with conical draft tubes discharging into the tailrace. The present structure is in reasonbly good condition, however, the approach channel is shallow and the concrete walls of the forebay have been seriously eroded over the 60 years of operation. Review of the original drawings shows plain concrete walls approximately 12 inches thick tapering to 9 inches at the top. With a negligible footing, height approximately 10 feet, rock backfill on one side and with full hydrostatic pressure on the other, the wall is just in the balance in terms of its structural stability. This becomes unacceptable when additional loads such as ice and saturated ground conditions are added or even dewatering of the forebay. The powerhouse is predominately of reinforced concrete, however, the portions of the plant which are against the original limestone rock face are plain concrete of varying thickness to suit the rough excavation. The turbine pit floor is approximately 2 metres above the tailrace and virtually all concrete which was poured below this level is unreinforced. The powerhouse relied on the bond between the plain concrete and the rock base for its stability and strength. Since the forebay walls were in poor condition any way, one reasonable way to rehabilitate the plant would be to enlarge the forebay and provide for more flow to enter the existing turbine pits. This is the fourth alternative, to install the largest equipment possible within the existing turbine pit. The initial study proposed that the present output of 900 kilowatts be increased to approximately 1.8 megawatts. This less complex alternative has the lowest cost of approximately three million dollars. - Recommended by Feasibility Study.

As the Commission went through the stage of prefeasibility and feasibility studies the urgency of their work was accelerated by the need to rewind the generator for the 550 kilowatt machine. In late 1986 the decision was made to go ahead with the rehabilitation of the plant using the largest units which could be fitted into the existing turbine pit. The logistics of the project were considered first. The cost of generator rewind was compared to the potential revenue available before installation and commissioning of the new equipment. The decision was made to proceed with the rewinding of the generator. The $44,000 cost of the rewind has been more than paid back as the benefit to the P.U.C. is approximately $5,000 per month in displaced costs from Ontario Hydro and the generator has now been available for 14 months.

The rehabilitation of the plant was broken down into two phases. Phase one, in 1987 was the reconstruction of the forebay to the plant. Phase two, in 1988 will be reconstruction of the tailrace areas and the completion of powerhouse modifications necessary to accept new generating equipment. Since the equipment selection could not be completed in 1987, the work in phase one stopped at the upstream face of the powerhouse.

The utility remained committed to the original open flume arrangement to reduce construction costs. The initial part of phase one was the preparation of civil drawings and specifications which were completed in August of 1987 and construction began in the beginning of September. Phase one work, included the partial reconstruction of the weir at the approach to the forebay, refacing of one forebay wall, reconstruction of the other, installation of new trash racks, and the removal of a couple of beams which had interfered with the flow of water entering the turbine pit. Once flooded and restarted the new forebay along with the clean turbine pit resulted in an increase of energy of approximately 45 kilowatts.

At the same time as phase one construction was underway the tenders were solicited from manufacturers of generating and turbine equipment. The tender requested the submission of a Francis turbine as the base bid while providing for alternatives. Six bids were received, three involved Francis equipment and three involved Kaplan. A comparison of equipment involves a number of factors from the subjective consideration of the experience of the various firms to the quantitative things such as the cost and the guaranteed energy output. In this case the decision was based on the technical merits of the proposal, the incremental differences in revenue and the cost of modifying the powerhouse to accomodate the equipment. The comparison was initially reduced to three fundamentally different alternatives. The basic bid was a 1.7 m diameter Francis turbine consuming 12.7 cubic meters of flow. The runner would be installed within the existing turbine pit and just above the old pit floor and would require a new draft tube and concrete encasment. It would be a 150 rpm unit, with 825 kw generator and generator speed of 900 rpm. Two equal units would be provided, one in each pit as the pits are nearly identical in geometry. The Francis alternative was attractive because it did not require serious modification of the existing powerhouse. Both of the other two alternatives considered in detail were Kaplan units.

Option B was 1.7 m diameter Kaplan which would also be installed just above the existing turbine pit floor elevation. It would have a turbine speed of 250 rpm, 720 rpm generator, a output of 1050 kw per unit consuming 14.2 cubic metres per second.

The third alternative, 'C' is also a 1.7 m diameter runner. In this case the runner would be set lower to provide the optimum output from the plant. Excavation beneath the existing powerhouse would be required - both into the rock and into the plain concrete which forms the foundation into the powerhouse. The runner speed is 204 rpm and the gross output would be about 1200 kw per unit. Each unit would consume more than 15½ cubic metres so that the plant rated flow would be at only the 30 percent tile.

In the final analysis the utility selected the second alternative Kaplan units with 2100 Kw capacity. The reasons, were first; the increase in revenue from $300,000 a year to $353,000 a year. Although the third alternative provided $378,000 per year in revenue, it was discounted because of the excavation beneath the powerhouse and the risk of disturbing the old structure. The superior revenue of the Kaplan unit was due to the flat efficiency curve and the broad range of flows over which this plant will be expected to operate. The long term efficiency dependability of the Francis units and the simplicity of maintenance was still a real attraction to the utility. However, the improvements in revenue available with the Kaplan machine and the successful experience of neighbouring utilities with Kaplan equipment was enough to justify the selection. The design and fabrication of the equipment is now well underway and the first shipment to the site has already been completed. The order which was placed approximately December 1, 1987 should be filled with commissioned plant on or about February 1, 1989. Mechanical designs were substantially complete in early June and it is now necessary to complete the civil design as fast as possible to permit commencement of the work in September. Almonte PUC will be dismantling the existing turbines and generators in August.

One of the interesting problems associated with the civil portion of the work has been modelling of flows and the necessary channel modifications for the approach and outlet from the plant. Once the phase one work was completed in December of 87, we had a full scale model of the forebay operating at 44 percent of the final plant flow, so head losses upstream were relatively easy to estimate. However, the tailrace is was narrow and steep with a rock wall on each side. Stage discharge curves were developed for the tailrace and for the main dam. Comparison of the curves revealed that the tailwater elevation rises faster than the forebay so the diversion of flows down the chancery channel would improve head at the plant. The installation of flashboards on the main dam was recommended prior to the commencement of construction. Fortunately the existing dam is already outfitted for a simple flashboard system comprised of metal posts and planking and this system has been used for many years in the past. An additional benefit of flashboards is that they increase the forebay depth during the winter and facilitate the formation of an ice cover. All the hydraulic information has been printed in a report which the utility will be able to keep on file to compare with the actual operation of the plant.

Another event which occured late in the project was the opportunity to purchase the Almonte Flour Mill which is immediately upstream of the town plant. The possibility of using the 8 km long forebay for peaking was considered. A brief study of the site was undertaken and three types of development were comprised:

700 Kilowatt Run-of-the River	2.7 million	Revenue	$121,000
700 Kilowatt Peaking - Same Cost	2.7 million	Revenue	$161,000
Gate Only	800,000	Revenue	$ 34,000

However the idea has been discounted for the time being because of the cost of purchasing the plant, as well as the concerns about oscillating upstream water levels and ownership of the other half of the river bottom. The mill was later sold.

A second event was the proposal of a private corporation to purchase the plant and lease it back to the utility for the tax advantages. This was very seriously considered, however, in the end it was not accepted. We understand that some adjustments in the February budget were directly attributed to this proposal.

The Town of Almonte is now looking forward to continued and improved use of the resource which was the focus of its initial development. The newly rehabilitated 2.1 megawatt Almonte Power Station will have cost approximately $3,000,000 or $1400 per kilowatt when completed in early 1989.

SESSION 17:

PROJECT FINANCE - INTERNATIONAL 2

Chairperson: J. Shepherd
Blaney, McMurtry, Aarons and Watson

Institutional Barriers to Private Investment in the World's Energy Market

By

W.B. Smith, M. Elaine Evans

45

INSTITUTIONAL BARRIERS TO PRIVATE INVESTMENT IN THE WORLD'S ENERGY MARKET: SMALL HYDRO '88, 7-4-9, 1988 Toronto, Canada

The United States encouraged extensive private sector participation in the electrical generation business as a result of the Public Utilities Regulatory Policy Act of 1978. The law resulted in: legislatively mandated power purchases by a utility from the unregulated producers within it's service territory, a variety of investment incentives, and the removal of significant regulatory burdens on the unregulated producer. It was a model that depended on a responsible capital market in order to work, and it spawned a new independent energy industry.

The US model is not directly applicable to countries that utilize government capital planning and control of their electrical supply needs. However, a number of these countries need electrical capacity. There are many examples illustrating what countries have done to encourage private investment in their domestic energy projects by offering incentives or by making their policies more flexible.

What are some of the key elements that make a project feasible and attractive to private investment, assuming the need for capacity and some demonstrated willingness from the host country to support privatization?

1. **Risk Protection:** To interest foreign or domestic private investors in a project it is critical to offer protection from potential economic and political instability in the host country. The most encouraging response to this need has come with the World Bank's formation of a Multilateral Investment Guarantee Agency, MIGA. It is designed to encourage the flow of investment within developing countries by issuing guarantees against non-commercial risk and by assisting in consultation and negotiation on the conditions for foreign investment in member countries with technical assistance. Perceptions of political uncertainties in developing countries and concerns about the the ability of their economies to assure the convertibility and transfer of profits probably constitute the major reasons behind both investment flows out of such countries.

The MIGA provides coverage of four broad categories of non-commercial risk. It has authorized other non-commercial risks upon joint application by investor and host country, with special majority decision of the agency's board. These four broad categories are:

(a) the transfer of risk resulting from host government restrictions on currency conversion and transfer;

(b) the risk of loss resulting from legislative actions or administrative actions and omissions of the host government which have the effect of depriving the foreign investor of his ownership or control of, or substantial benefits from, his investment;

(c) the repudiation of government contracts in the cases where the investor has no access to a competent forum, faces unreasonable delays in such a forum or is unable to enforce a judicial decision issued in his favor; and

(d) armed conflict and civil unrest.

Coverage may include equity interests as well as non-equity forms of investment such as service and management contracts, licensing and franchising agreements, and turnkey contracts, provided the contractor's compensation is substantially dependent on the production or profits of the assisted enterprise.

All eligible investments must represent a provision of assets for productive development of the host country, comply with its laws and regulations and be consistent with its development priorities. Projects serving military purposes are not eligible. This program should significantly ease investors' fears about investments in developing countries.

The MIGA Board of Directors has been elected and their first meeting was June 22, 1988.. Currently 42 member countries have subscribed, providing about 63% of the Agency's authorized capital of $1,082,000,000. The interim administration is now drawing up guidelines for application to MIGA's program.

2. **Availability of Capital**: All countries are concerned with the development and operation costs in their power sector. Frequently the countries that have the greatest need for energy projects cannot raise the capital internally and are unable to incur more debt with the international loan agencies.

Pakistan has designed a creative solution to needed funding for their energy development with a new **Multi-Donor Program** financed by the World Bank, USAID, UK and Italy with other potential contributions from Japan, W. Germany and France. The program's key elements are:

A. The donors provide loans and grants designated for this program to the Government of Pakistan .

B. Government of Pakistan provides these funds to the Energy Development Fund at an interest rate of 7%

C. After selection of a viable project The Energy Development Fund loans these funds to private investors for up to 30% of a project's total cost.

D. The investor must provide 25% equity in the project

E. The loan terms are uniform: 14% interest, 23 year term, with an 8 year grace period.

The program's goal is to make a certain percentage of a project's capital needs available in a stable and fair manner. The first project to go forward will most likely be a 1200 MW oil fired generation station, but request for renewable energy projects are in the works.

The **Build,Operate and Transfer** (BOT) model is another system that encourages private investment for needed capital in project development.

The BOT model is another effective way for greater private sector participation in areas traditionally under government monopoly. With increasing emphasis on privatization of state-owned enterprises all over the world, the BOT model has found support from both the international banking community and the contractors who are interested in pursuing the work opportunities. Export-import credit authorities from the US, UK, France and Japan have become interested in exploring support for projects under a BOT model.

The Turkish government has acted as a pioneer in BOT model applications. In the past two years, the Turkish government has solicited foreign contractors for proposals on various energy and transportation projects and held negotiations to develop a framework for a BOT model that is acceptable to both government and the contractors. Energy projects generate revenues and lend themselves well to heavy leveraging. Energy is in short supply and with demand increasing dramatically the profitability of these project financed energy projects have attracted the interest of contractors from a dozen countries.

The Turkish Electricity Board (TEK), a state monopoly, will be the sole buyer of the energy. They will transport, and distribute the electricity and collect the tariffs. TEK has agreed to buy-back rates that ensure coverage of the projects' operating costs, service debt, equity payments and an expected rate of return depending on the project's financial characteristics of 13% to 20%.

The BOT model involves foreign contractors in a joint venture with a domestic partner to establish a project company, who then build, finance, manage and operate this company over a typical period of 10-15 years. After that period, the foreign company is encouraged to transfer its equity share or the entire firm to another private or public entity. BOT models have an inherent advantage for governments which normally would be forced to allocate scarce foreign exchange to develop specific projects.

In the BOT model, the public investment is substituted with foreign investment with vested interests that ensure its profitability because the return on investment depends on the project's competent management. Often in the past,foreign contractors have completed a project, turned over the keys leaving the country with no concern about its operation, profitability and efficiency. The BOT model introduces a connection between cost efficiencies and investment return maximization from all the project's participants.

Projects using a BOT model bring much needed foreign management skills and investment to the country. Loan appraisals are more often more favorable to these projects relative to projects managed totally by domestic companies. Attracting foreign capital enables governments to keep their own budget resources for projects high in "social benefit" but low in revenue generation. BOT model allows for transfer of traditionally state owned enterprises to the private sector. Privatization of these operations relieves the government from the financial burdens of heavy subsidies frequently given to state-owned enterprises. It also brings together in an efficient way the public and private sectors in large investments projects with long term objectives.

But as with all complex issues the BOT model can pose problems for the investor. The life of this type arrangement is long and often fraught with constraints that may create considerable frustration for the foreign investor. Then there are the pending questions on how to accurately assess a counrty's political, financial and regulatory risks over such a long period. Frequently many of the projects needed are in areas where making to make it profitable to foreign investors will exceed "reasonable" user charges during most all of the 15-30 year project life. Demonstrating it is more difficult to structure a successful privatization model for the socially beneficial project.

In the Far East and South East Asia there are signs of more involvement in the power sector by foreign interests and private sector investment could occur in the near future.

Malaysia has recently commissioned a merchant bank consortium to do a feasibility study into privatizing the state-run National Electricity Board. The form this action might take is undecided but may be privatized by issuing public stock in the Board or by dividing the power generation, transmission/distribution division and selling them off as individual units.

The concept of privatization is also gaining support in the Philippines. The State-run but privately owned Manila Electric Company is talking with the Asian Development Bank to fund a feasibility study for full privatization of their Company. The financially troubled utility was previously all under private control prior to the Marcos era which placed it under government management.

Singapore is looking at privatizing the government run Public Utilities Board (PUB) which supplies Singapore with all its electricity, gas and water requirements. Here, the motivation may be more driven by political concerns than financial need. The selling of the PUB would help the government strengthen the the Singapore stock market and encourage Singaporeans to invest in their own companies.

3. **Artificially low power rate:** In many countries the domestic rates for power have been subsidized for political reasons When an independent company proposes a project and confronts these very low buy-back rates, a project loses its economic feasibility. One response has been direct sales to industrial customers. Often supplying directly the generation capacity needs of a large industrial user is welcomed by the utility faced with the shortage of development funds and inability to meet supply needs.

The Dominican Republic's national utility, CDE, has a cost of electricity of approximately $.12/Kwh (U.S.). The customer's rate in the RD is approximately $.06/Kwh (U.S.). The difference in rate is subsidized by the government under a policy to provide the majority of people in the country with electricity. This subsidization creates a continuous drain on the government treasury. Currently the DR government is examining ways to reduce the current cost of electricity which comes primarily from imported diesel fuel, and to develop lower cost alternatives. Thus, the most plausible avenue is to develop projects near the customer's point of demand and sell directly or wheel over existing transmission lines. Excess capacity may be sold at a reduced rate to the host government in exchange for reduced or minimal wheeling charges. Remote development also provides reliability at the end of the grid.

In the US, the major investor owned utilities have created arms-length subsidiary companies who have aggressively pursued market opportunities as independent developers. An unexplored option for para-state utilities would be joint venturing with the state-owned utility's sub-unit acting as a developer and a third party as investor. It could be advantageous for a para-state utility to develop a "spin-off" company to participate as an equity partner with a private developer in a joint venture. However, to overcome traditional hostility to outside investment from the host utility, incentives must be created to encourage their participation in any project using private investment. When the idea for third party involvement has come from the government there has been much more cooperation with the independent development entity.

Private investors rely on a timely process. An accurate assessment of lead times, contractual negotiations, and constructions times is essential before a project's financial viability can be evaluated. This requires building incentives for "timeliness" into a centrally planned process.

Private investment requires a rate of return and confidence that the investment is secure. This can run in opposition to the prevailing philosophy of the government/utility. It requires imagination and creativity to work out an accommodation to what appears to be a conflict. However, if common concerns and mutually desirable goals are clearly identified, solutions can be found.

Greece is another country experiencing a steady increase in energy consumption and need for electrical capacity. To stimulate interest in private activity in electrical generation, Greece established a Public Law 1995, which with some limitations, is very similar the the US's PURPA. It allowed the production of electrical energy by independent power producers, emphasizing the use of renewable technologies as the fuel source, and mandating sales with the Public Power Corporation. Cogeneration is also permitted within specific parameters. The buy-back rates for private producers to sell their surplus is equal to 100 percent of the PPC tariff. Due to constraints in the size of projects able to use PL 1995, it is likely that this vehicle will generated more domestic investment than foreign. Figures on the total amount of new capacity developed under the provisions of this law are not yet available, so it is unclear if this legislation met the Greek governments objectives.

Privatization is the latest "buzz" word in financing. It is thought of as the solution to the international funding problems facing developing countries. As this paper illustrates many countries are now investigating a new range of options to finance energy projects that utilize the concept of private investment. The infusion of foreign technology, know-how, management skills and investment capital has great benefit to the host country. There are additional benefits to the host country of encouraging domestic investment which enhances stability, improves the balance of trade and developes indigenous resources.

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Small Hydro and Project Financing: A Bank's Perspective

By
G.S. Newson, A.W. Reid

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SMALL HYDRO AND PROJECT FINANCING:

A BANK'S PERSPECTIVE

Presented by

G. S. Newson

at

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Prepared by:

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I. Introduction

I would like to begin by saying how pleased I am to have this opportunity to speak at the Small Hydro '88 Conference today about the financing technique known as "project financing" and its application to small hydro development. I am a senior manager in the Corporate Finance Division of the Canadian Imperial Bank of Commerce, known as "CIBC" for short, at our head office in Toronto, where we have engineered some of the original financing techniques which are now applied on a worldwide basis in the discipline of project financing.

Let me very briefly describe CIBC and the relevance of its operations to the small hydro industry. In 1987, CIBC had total assets of Cdn$88.4 billion, roughly US$73 billion, putting it in the top 10 banks in North America. CIBC has more than 1,600 branches and offices worldwide in 23 countries, and is represented in 11 cities in the United States. We have Corporate Finance experts based in Chicago, Los Angeles, New York and Toronto engaged in specialized financing areas such as trade finance, acquisition and LBO financing, tax-driven financing and, of course, project financing.

It is this latter approach which is aptly suited to small hydro development. CIBC has successfully used project financing to finance both parallel generation and co-generation facilities, from small hydro plants to large generating stations in Canada and the United States. We view small hydro as an important and growing industry with potential benefits to all parties involved.

I hope that this presentation today will leave you with a clearer understanding of project financing, in what circumstances it is most applicable and how it would best be structured to meet the needs of the sponsors of a project and the financial institutions providing the funds. In the final analysis the structure of any financing will depend on the financial and operating risks associated with the project and how the parties committed to the project negotiate the sharing of the project risks.

These comments will be better understood once we have explored in more depth how project financing came into being; what the typical risks associated with a project are; how these are identified and shared; and how project financing meets the needs of small hydro developers.

II. Description of Project Finance

Project financing is applied to a project where the components of the deal are self-contained. The assets of the project can be isolated and operated to provide the cash flow which alone will cover all operating expenses and service the debt; the input to the production process can be provided either under contracts exclusive to the project or by some other means which assures access to the input supply for a period of time adequate to allow for full loan repayment; the product or project output is provided to a unique market which again must be assured for a length of time adequate to absorb sufficient volume at a satisfactory price to meet operating and debt service requirements.

As can be seen, small hydro developments are well suited to this method of financing. The project's assets and its ability to generate cash flow can be isolated. The project's feedstock, in this case waterflow, can be estimated with the extensive hydrological data which is normally available. The total output from the project is usually purchased under contract by a provincial or state utility for as long as the plant is in operation.

Project financing is also often referred to as limited recourse financing to indicate that banks may share the risks of project completion, operation, marketing, pricing, sales, technology, etc. with the project sponsor.

From the lender's point of view, the security which can be obtained on tne project must allow him or her to be able to take over the entire operation in case of financial or operational difficulties for, as banks have found out the hard way, the hard assets of a project rarely carry a resale value which approaches the amount of the financing required to develop the project unless they are in operation. In other words, if assets are sold on a piece meal basis, they will be worth substantially less than the amount of the loans against them.

III. Historical Perspective

I would like to take a few minutes to give you an historical perspective of project finance. At CIBC, we feel that project financing has gone through three general phases since we first became involved.

1968 - 1976

As a result of certain legislative changes in Canada and a stronger economy in the 1970's, there were increased bank lending activities, and as an outgrowth thereof, project financing opportunities. Project financing entered the marketplace as a new product, being addressed or sold by banks with mainly commercial lending experience. During this period risk allocation was primarily in the direction of the borrower. The banking industry's ability to assess risks had not been developed to its present state and there were limited banks in the field.

1977 - 1982

A number of changes in the project finance lending marketplace occurred during the late 1970's and early 1980's. This period featured an inflationary push for commodity prices and costs, some economic expansion, and a great movement of capital into the energy sector. The perception of commodity prices continuing to rise faster than operating costs made project financing a most attractive option for lenders and enhanced their ability to proceed with the financing of very substantial capital projects while sheltering themselves from the downside if their judgment proved incorrect. Competitive pressures encouraged banks to accept more of the project risks. When the inevitable downturn in cyclical commodity prices appeared, prices fell but inflation of operating costs continued, albeit at lesser rates, and interest rates remained high. This forced lenders to reassess the fundamentals of project finance and to focus on lending opportunities where the operating costs were low relative both to the prevailing market price of the product and to competitors' operations.

1983 - the Present

It is our view at CIBC that today the risk analysis process in project financing has reached a mature stage. Most of the involved institutions have developed significant in-house expertise - expertise that has been tested in good times and bad. A current-day lenders eagerness to participate on a project finance basis is reflective of his assessment of efficiency, usually in terms of operating cost, of a particular project relative to competing capacity existing and planned in its market.

As to remuneration for risks, project financing is currently a mature service being provided at a price that more and more accurately reflects overall risk.

In the next few minutes I will discuss in greater detail the risks associated with a project and methods that are available for their mitigation in a project financing structure.

IV. Identification and Mitigation of Risk

The basic principle that allows an economic unit or entity to be considered for stand-alone project financing is that the business risks associated with a specific project can be identified and managed. It has been our experience that project financing risks and possible means of managing these fall into the following broad areas:

(i) Security of Input/Feedstock - Typically supply contracts are required by lenders to guarantee quality, volume, price and term of the inputs to the project. In the small hydro setting, this is not possible as the facility will be dependent on waterflows. The risk of low waterflow in a given year will be assumed by the lender. The risk is mitigated through analysis by hydrologists of the waterflow records for the river and site in question. The lender must recognize that small hydro projects have long lives and waterflows will "average out" over an extended period of time.

(ii) Completion - Completion risk encompasses two aspects. The first relates to the sponsor's ability to complete the project within the estimated capital cost budget and on time. The second concerns the project, upon completion, attaining its planned output in accordance with the stipulated completion tests. In other words, will the project work as planned. The lender will not take on completion risk unless proven technology is used and experienced contractors, engineers etc. are involved. Although some of this risk may be allocated to the lender by its acceptance of the basic engineering and construction reports and plans, the majority of the risk will be allocated to the sponsor and may be mitigated by use of fixed price contracts, completion guarantees, prearranged borrower-based cost overrun funding, performance bonds, turnkey engineering or construction contracts and the like.

(iii) Output Volume and Prices - Lenders are interested in focusing on whether or not the project will sell enough of its output at a price sufficient to service its obligations. In appropriate projects the bank will be willing to accept certain price risks but no volume risk. Mitigation of the risks for both the lenders and the sponsors can be attained through take-or-pay contracts for fixed volumes and/or fixed prices, and cash flow deficiency agreements. In the small hydro context, and with regulation of provincial and state utilities, it is common to find policies or legislation in place whereby long-term contracts are available for total output to be purchased at fixed rates or minimum floor rates.

(iv) Management/Ownership - Critical to any endeavour, whether project financing, commercial lending or equity investments, are management and ownership. Lenders must have the utmost confidence that management and sponsors are committed, have the necessary technological, industry and project management experience, and, if necessary, sufficient financial strength.

The foregoing oversimplifies the complex structure of project financing transactions. It does, however, hint at some of the many tools available to both lenders and borrowers in protecting themselves against some of the inevitable risks associated with a financing that is dependent solely on one project's assets and cashflow for debt servicing and return to the sponsors. All of these mitigating measures plus hundreds of other factors are open to study and negotiation.

A strong spirit of cooperation between borrower and lender combined with expertise on both sides is normally required to produce a successful financing.

V. Project Financing - Meeting the Needs of Small Hydro Sponsors

I would now like to focus on the ways in which project financing can meet the needs of small hydro sponsors. In our dealings with a number of sponsors, five areas were frequently mentioned: (i) knowledgeable lenders; (ii) commitment (iii) timeliness; (iv) reduction in risk to the sponsor; and (v) flexible financing structure. I will deal with each of these in turn.

(i) Knowledgeable Lenders - As mentioned, it is critical to the success of any project that the lender and sponsor work together to structure the financing properly and to overcome the many obstacles which will inevitably arise prior to completion. A sound working knowledge of the industry on the part of the banker facilitates this and allows him or her to respond quickly to the concerns of the sponsor. Project lenders are finance specialists who deal with projects in a number of different industries. Skills are acquired which can be applied in the small hydro context. At CIBC, we target developing areas and make a point of obtaining relevant industry information and meeting industry officials, spokesman, etc. to provide us with the necessary background knowledge.

(ii) Commitment - Financing of a project is a critical aspect to the small hydro sponsor and the lender is going to play an instrumental role in the success of any project. The sponsor wants a lender that works with him to provide advice and appropriate financial structuring. Not only does the bank have extensive experience, but it also has a great deal at stake in a project financing and as a result has the necessary commitment and willingness to see the project succeed.

(iii) Timeliness - The timetable for a small hydro project is generally quite tight and the developer is looking for quick decisions and turnaround. With the amount of analysis, meetings, due diligence and documentation involved, project lending is very time intensive. The organization of CIBC's project finance group is designed to handle these time restrictions. Teams of two or three finance specialists can dedicate themselves to a particular deal to see it through to completion. In the first small hydro deal we financed, we were able to advance funds three weeks from the date of our first meeting with the project's sponsors. While this was an unusual circumstance, it did, however, demonstrate CIBC's ability to respond quickly to the sponsor's needs. The time frame from the first meeting to the date of completion can in fact be very lengthy depending on the stage of preliminary plans, regulatory approvals, equity financing etc.

(iv) Reduction in Risk to Sponsor - Sponsors want to protect non-project assets and have as much certainty as possible when financing a small hydro facility. By its nature, project financing or limited recourse financing reduces the risk to the sponsor. This means that the lender will be looking only to project assets for repayment of the debt and there will be limited recourse to the project's sponsors. As discussed earlier on project risks and methods to mitigate, the bank will analyze a project to determine the risks involved and will decide which risks it is going to assume. Requirements such as fixed price construction contracts, performance bonds, etc. protect both the bank and the sponsor, and will provide reasonable certainty as to construction costs, workmanship and performance of the facility.

(v) Flexible Financing Structure - The structure of the financing can take a myriad of forms. A major concern with small hydro after completion is the dependency of revenues on waterflows. If there is a low water year and the debt repayment schedule does not contemplate fluctuations in cash flow, the loans will be in default and will require time and money to rectify. The ability to structure the financing to deal with water fluctuations goes back to my first point - understanding the industry drives the rest of the financing. In this instance the lender must recognize that hydro installations are long term assets and that water flows, while subject to yearly variances, will average out over a suitably long period of time. This concern can be addressed in a number of ways depending on the circumstances of a particular deal, such as building in allowance for slippage; establishing a fund from excess water flow years which will be drawn upon in future years to service debt; or to have mandatory prepayments of the term debt in years of excess water flow which will reduce the debt at acceptable rates.

VI. Typical Financing Structure

Perhaps the best means of illustrating everything I have talked about is to briefly go through the key elements of a typical structure of a small hydro financing and point out what we would look for, the amount of financing available and the terms and conditions applicable. These matters are negotiable, of course, but hopefully this will give you a better idea of what will be available at CIBC in terms of project financing.

(i) Approaching the Bank - it is appropriate to first meet with your potential lender in the early stages of development, likely after site approval has been received. At this time you can determine the range of debt financing that will be available, basic terms thereof and the lender's requirements before a commitment and the ultimate financing will be completed.

(ii) Level of Financing - The debt capacity will vary project to project and will principally depend on the projected cash flows of the project and on the track record of the sponsors, particularly if they have already done a project with the lender;

(iii) Form and Term - The revolving construction loan will convert to a term loan upon completion of the project. The term facility may be for a period not exceeding 10 years, but possibly structured with lower principal repayments in early years due to the high leverage, and a balloon payment of up to 1/3 of the loan due at the end of year 10.

(iv) Interest Rates - Interest rates will be higher during construction to reflect the higher risk prior to completion. Once the project is completed and operating as planned, the risk over the repayment period is greatly reduced. It is at this time when other institutions, pension funds, insurance companies etc. that are not geared towards construction financing, may become interested in the term financing for the project.

(v) Security - As mentioned, the bank will need to put itself in a position to be able to complete construction and operate or sell the project in its entirety as an ongoing business. This means that security over all assets, material contracts and receivables will be required.

(vi) Terms and conditions

Use of Consultant - Project lenders, although having a working knowledge of the industry in question, require assistance on the technical side. CIBC will require an independent consultant to review the feasibility study, talk to the contractors, turbine suppliers and project sponsors, and to provide the Bank with an independent opinion regarding the operating and construction economics and technical merits of the project. During construction the consultant will make periodic visits to the site to monitor construction and provide the Bank with an independent view of compliance of contractors to the construction plan and review quality and cost of construction and provide a record of the progress of construction.

Regulatory Approvals - All consents and approvals necessary to construct the project will be required before closing the financing. Allowance is made for certain approvals, such as under the Navigable Water Protection Act and the Public Lands Act in Ontario, which will not be available until the project is completed.

Output Purchase Contract - A satisfactory contract to purchase the output of the facility will be required. The Bank will focus on the issues of term, rates, escalation of rates and capacity factors.

Construction and Performance Agreements - Fixed price construction contracts, 100% performance bonds, a fixed price turbine contract and technical operating rate guarantee will be necessary on terms satisfactory to the Bank.

Equity Injection - The equity will have to be injected and drawn completely prior to the draws under the debt financing.

(vii) Expenses - The final item bears directly on the economics of project financing. All out-of-pocket expenses of the lender are typically for the account of the sponsors. This includes legal and consulting fees, travel etc. In addition, due to the commitment by the lender and the time involved to structure and monitor the financing of a project the lender will charge a fee. In total these expenses and fees can be considerable, ranging typically from 2% to 5% of total project costs, and since they vary little with the amount of the financing or the size of the project, economic prudence suggests a minimum capital cost threshold for projects of at least $3 million to qualify for project financing unless there are special circumstances. If project financing is not available, traditional bank financing would be an alternative.

VII. Conclusion

We have discussed project financing techniques and some of the experiences of CIBC, and applied these in the context of small hydro.

In summary, project financing is highly complex and the parties involved are numerous, ranging from project sponsors, lawyers, bankers, consulting engineers, governments, and investors. A popular anecdotal expression amongst those who have been exposed to the frustrations of co-ordinating all these parties, structuring and documenting these deals is the six phases of project financing. These are said to be:

1. enthusiasm,
2. disillusionment,
3. panic,
4. search for the guilty,
5. punishment of the innocent; and upon successful conclusion of the deal,
6. praise and honour for the non-involved.

On that note, let me conclude by thanking you for the opportunity of being with you today. It has given me a chance to reflect on a number of the issues surrounding project financing and I am delighted to have had the opportunity to do so in such pleasant surroundings and company. I would be happy to answer your questions if you have any.

Authors' Backgrounds

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SESSION 21:

SMALL HYDRO MARKETS

Chairperson: I. Efford
Efford Avocet International Ltd.

The Role of Small Hydro Power Stations in the Rural Development of the North-Eastern Regional of India

By
D. Kedia

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SMALL HYDRO '88

THE ROLE OF SMALL HYDRO POWER STATIONS IN THE RURAL DEVELOPMENT OF NORTH EASTERN REGION OF INDIA

SMALL HYDRO '88
TORNOTO
CANADA

8TH JULY 1988

D. KEDIA
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INDIA

THE ROLE OF SMALL HYDRO POWER STATIONS IN THE RURAL DEVELOPMENT OF THE NORTH EASTERN REGION OF INDIA

D KEDIA

The Indian subcontinent is spread across the southern slopes of the great Himalayas. It is a large country covering an area of 3.28 million square kilometres, and supporting an estimated population of 800 million people. As much as three fourth of her population lives in the more than 576,000 villages spread out to the different nooks and corners of the country.

The north eastern region of India lies at the foot of the eastern most Himilayas, and consists of seven states!

Contd...... 2/

1) ARUNACHAL PRADESH
2) ASSAM
3) MANIPUR
4) MEGHALAYA
5) MIZORAM
6) NAGALAND
7) TRIPURA

The region covers a total area of 255,000 square kilometres and caters to a population of 26·6 [redacted] million (1981 count). The overall population density of the region is 104 persons per square kilometre, compared to the national average of 216 persons. However, the density varies from a low of only 8 persons in Arunachal Pradesh to 254 in the fertile plains of Assam, (Table 01).

The territory covered by this study has a high incidence of rainfall, ranging from 110 cm to 635 cm and it incorporates the highest rainfall areas of the world including Cherrapunjee and Mawsymram.

The region is drained primarily by the great BRAHMAPUTRA river, which originates as the YARLUNG ZANGBO JIANG in Tibet. The peak discharge of the river at GUWAHATI has been recorded at 72,570 cumecs (2.57 million cusecs).

The Brahmaputra Valley is shaped like a long bowl with an opening on its western end. Innumerable small and large streams contribute to the flow of the main river. The total specific discharge at 3.03 cusecs per squaremile for the Brahmaputra, is one of the highest for any river in the world; which is contributed by the high rainfall in its catchment.

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The hilly topography of the region, coupled with cupious rainfall, offer innumerable possibilities for the installation of small and medium hydel power stations.

HYDEL POWER IN INDIA

The total installed capacities in India (MW), and the annual electricity generation (GWh) are shown in Table - 02. The share of hydel power at 16,657 MW out of a total installed capacity of 51,500 MW is around one third.

It is very relevant at this stage to have a look at the identified hydro potential in India as estimated by the Seventh Plan working Group (Table - 03). The disproportionate exploitation of available hydel potential amongst the different regions of the country cannot be more eloquently projected than in this tabulation.

The north eastern region with 35.5% resources of the country is still languishing with a mere 0.5% exploitation of its identified reserves.

The identified hydel installed capacity of the north eastern region is estimated at around 50,000 MW. Of this, one single project at DIHANG, on the river BRAHMAPUTRA has been designed to have an installation totalling 20,000 MW.

Another mighty site, not yet investigated, lies at the bend of the YARLUNG ZANGBO JIANG around the NAMJAGBARWA peak in Tibet. From Pai to Xirang village, the river descends a total of 2,200 metres within a run of 240 kilometres along its course. A tunnel through the Himalayas, connecting the above two points, will be of 38 kms length and the river could be diverted to power a hydroelectric plant producing an astronomical 40,000 MW. It could be the mightiest the world has ever known.

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SMALL HYDRO IN INDIA

The estimated total Small Hydro potential in India has been evaluated at about 5,000 MW from medium and high head installations and an additional 5,000 MW possibility by exploiting the irrigation canal drops. As of mid-1986, around 120 small hydro stations comprising of 290 sets having a total installed capacity of approximately 220 MW, were operational. Around 125 more power stations with an installed capacity of 200 MW were under construction. A great stress is being given by the Government to exploit more and more small sources. By the end of the seventh Five Year Plan (1985-1990), the total installed capacity in the country is likely to touch 500 MW mark.

CATEGORISATION OF SMALL HYDRO

The Central Electricity Authority of the Government of India, has propogated the following categories for small hydro plants :

A) **SMALL HYDRO PLANTS :** Those plants with less than 15 MW total installed capacity, with individual unit rating between 1.0 MW and 5.0 MW.

B) **MINI HYDRO PLANTS :** Those plants with less than 2 MW total installed capacity with individual unit capacity rating from 100 KW to 1.0 MW.

C) **MICRO HYDRO PLANTS :** Those plants with less than 100 KW total installed capacity having individual unit capacities of a few KW to 100 KW.

HISTORICAL DEVELOPMENT OF SMALL HYDRO IN THE REGION

The use of flowing water as a source of power is not new to the population of this region. The Arunachalis have been using vertical water wheels for grinding of corn on a community basis and the people in the plains have used the energy of flowing water for the husking of paddy.

Contd...... 5/

The first ever electric power generation station in India was installed at Darjeeling in Eastern India before the turn of the century. Some tea gardens in Assam, had installed low head hydel turbines to serve as mechanical prime movers in the first quarter of this ~~country~~ century. The first organised venture towards an electrical utility for power supply was the Shillong Hydro Electric Co. which was commissioned around 1920 to supply power to Shillong Town. Another project near the capital town of Imphal in Manipur was commissioned by the British Government in the year 1932.

Till independence in the year 1947, no other hydel project was executed in the region. The Umtru Project, which was commissioned in July 1957 has an installed capacity of 4 x 2.8 MW.

It was only since around 1970, after the old NEFA (North East Frontier Agency) was reconstituted into the Union Territory of Arunachal Pradesh, that a sincere thrust was given to the development of mini and micro schemes in the region. This State, bordering China, today has a total installed capacity of 19.52 MW, of which 13.42 MW is from small hydro stations and the rest is all from small diesel sets.

NORTH EASTERN REGION - POWER GENERATION SCENARIO

The total installed generating capacity in the entire North Eastern Region was 889.80 MW, as of November 1987 (Table 04).

There are certain very interesting features, which can be analysed and observed from the accompanying tabulation :

Contd....... 6/

- Thermal stations cater for more than half (494.9 MW) of the installed capacity of the region.
- The major and small hydro stations together generate 319 MW of power, which is 35.8% of the total capacity.
- Major hydel schemes are operational only in Meghalaya. (114 MW) apart from the two Central Sector Projects generating 155 M.W.
- The total small hydro capacity in the region is 49.43 MW which is 15.7% of the total installed hydel capacity of 319 MW. (Table - 05)
- However, of this, the two 'small' stations at UMTRU in Meghalaya (11.2 MW) and GUMTI (15 MW) in Tripura account for a major share and the balance 23.29 MW consists of mini and micro stations.
- Arunachal Pradesh has a maximum number of 24 stations, with an installed capacity of 13.42 MW. None of these stations is individually rated above 2000 KW.
- Apart from the two developed States of Asam and Meghalaya, the other states are almost solely dependent on small hydro and diesel power stations. The installed capacity of small diesel generating stations is about one and half times that of the small hydro stations.

RURAL ELECTRIFICATION

The level of rural electrification in the states of the north eastern region is reflected in Table - 06. Most states in this region are yet to achieve the national average of village electrification, which was 71.5% as of March 1987.

Contd......7 /

OPTIONS FOR RURAL ELECTRIFICATION

The options open to the authorities for extending the power facilities to the masses are not very many. The difficult terrain of the region, in most states except Assam, discourages the extension of long distribution lines. Apart from the initial high investment, these lines are extremely difficult and costly to maintain.

The other alternative available is the provision of diesel power plants. Although these plants can be very quickly installed, the generation cost of this mode is prohibitive. In certain remote locations of Arunachal Pradesh, the fuel is carried by head load or dropped by helicopters. Naturally, no such scheme can be made economically viable.

Under these constraints, the role of small hydel schemes assumes very great significance in this region. It is, therefore, not surprising that most of the states in the region are dependent on this source of power to a great extent.

COST OF INSTALLATION

The Rural Electrification Corporation Ltd. (REC) is a Government of India undertaking catering to the financial needs of the State Governments. The REC has now started financing small hydro schemes upto a maximum capacity of five MW or a maximum project cost of Rupees fifty million (US Dollars four million).

The regional office of the REC has taken up ten such schemes recently for financing. The enclosed Table - 07, gives the salient costing figures of these projects.

Contd...... 8/ ,

It is interesting to observe that the per KW installed cost varies from US §.825.00 (1987-88 price level) to US §.3,000. The head and capacity of the project, have a direct bearing on the cost. The cost of power generation from these schemes is varying between 50 paise to One rupee fity paise equivalent to three to eleven cents in US currency. The REC has found these costs quite viable in comparision to the alternative of drawing long transmission lines to these remote areas, or installing diesel generating sets.

In another earlier sutdy conducted by the author on the year 1985-86 for 25 other schemes which had been installed and commissioned between the years 1975 to 1985, it was observed that the installed cost per KW was betwen US §.500.00 to US §.1,000.00 at the price range then prevailing.

The salient features of the schemes that were studied are given in Table 08 enclosed.

THE CONSTRAINTS AND THE PROSPECTS:

Inspite of the apparent advantages of the small hydel schemes and their suitability for the North Eastern Region of India, the actual pace of development is not very satisfactory.

Some of the major constraints faced in the execution of these projects are:

- The small hydro technology is still not being accepted as an indepen-

Cont'd 9/-

dent field of operation. Quite a few projects have been designed and executed as miniatures of large hydro plants, which does not always suit the local conditions.

- There is a general scarcity of trained manpower to this specialized field of operation.

- Hydrological datas of possible sites are not, readily available, due to which a great deal of time is wasted in the preparation of the preliminary report.

- The viable sites are very remotely located. As such, the development of infrastructural facilities prove to be very expensive and time consuming.

- The plant load factors are extremely poor because of the virtual non-existence of off peak loads.

- There is no good and reliable interconnection of the stations amongst themselves or to a regional grid. The utilisation of power at different load centres can be greatly improved if the grid connections are available.

- The terrain is geologically unstable due to which the civil construction costs are higher and the silt content is very high,

Cont'd...10/-

The following are a few suggestions to improve the pace of small hydro power development in the region:

- A special pool of experts must be developed for this field of engineering, who should be trained specifically for the small hydro operations.

- Steps must be taken to improve the off peak loads by encouraging small industries. Day time utilisation of power can be made to run pumps for lifting of water.

- Micro sized plants of the range of 10/20/40 KW should be encouraged to power very remote villages from independent sources.

- Such projects need not be planned on the 90% water availability basis, which is the standard norm. Even if the power generation is low during the dry months, other viable alternatives like Solar or Bio energy plants may be considered to boost the generation.

- The management of such plants must be handed over to profit motivated corporations or co-operative societies, who will give importance to the commercial aspect of the utility.

In spite of all the existing constraints in the development of small hydro schemes, the author strongly feels that this source of power generation is still the best and most viable means for the rural development of the north-eastern states of the Indian subcontinent.

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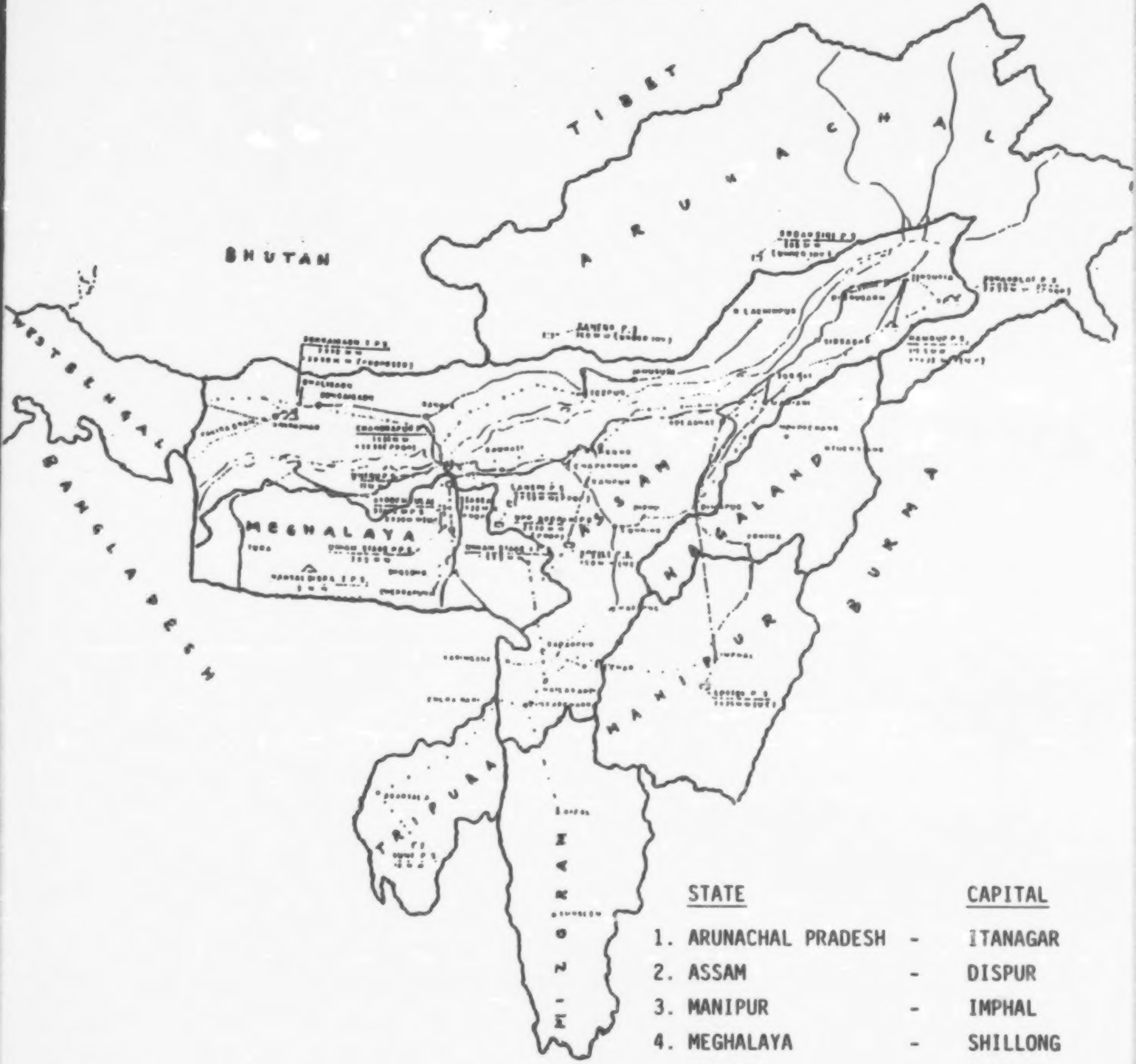
INDIA - NORTH EASTERN REGION


TIBET
ARUNACHAL
BHUTAN
WEST BENGAL
BANGLADESH
MEGHALAYA
ASSAM
NAGALAND
BURMA
MANIPUR
TRIPURA
MIZORAM

STATE		CAPITAL
1. ARUNACHAL PRADESH	-	ITANAGAR
2. ASSAM	-	DISPUR
3. MANIPUR	-	IMPHAL
4. MEGHALAYA	-	SHILLONG
5. MIZORAM	-	AIJAWL
6. NAGALAND	-	KOHIMA
7. TRIPURA	-	AGARTALLA

TABLE - 01

NORTH EASTERN REGION OF INDIA

STATE	AREA (1000 Km^2)	POPULATION (LACS)	POPULATION DENSITY PER SQ.KM.
ARUNACHAL	83.7	6.31	8
ASSAM	78.4	198.96	254
MANIPUR	22.3	14.20	64
MEGHALAYA	22.4	13.35	60
MIZORAM	22.1	4.93	23
NAGALAND	16.6	7.74	47
TRIPURA	10.5	20.53	196
TOTAL N.E. REGION	255.00	266.02	104
ALL INDIA	3,287.31	6852	216

Notes :

1. Source : INDIA - 1983, Publiciation Division
2. Population figures correspond to 1981 census.
3. Assam's population figures have been projected for 1981.
4. The area figures for Arunachal Pradesh and Meghalaya are provisional.

TABLE - 02

INDIAN ENERGY SCENARIO

TOTAL INSTALLED CAPACITY

	TOTAL INSTALLED GENERATING CAPACITY		TOTAL ELECTRICITY GENERATION	
	(February'88)		(1987-1988)	
	MW	(%)	G Wh	(%)
HYDEL	16,657	(32.3%)	43,663	(23.8%)
THERMAL	33,613	(65.3%)	135.509	(73.7%)
NUCLEAR	1,230	(2.4%)	4,652	(2.5%)
	51,500	(100%)	183,824	(100%)

TABLE - 03

INDIA'S HYDEL POTENTIAL

REGIONAL DEVELOPMENT

REGION	ESTIMATED ANNUAL ENERGY POTENTIAL (Twh)	SHARE OF ALL INDIA POTENTIAL (%)	DEVELOPED ANNUAL ENERGY POTENTIAL (TWh)	PROPORTION OF ENERGY DEVELOPED (%)
NORTHERN	157.76	33.4%	15.54	9.08%
WESTERN	36.95	7.8%	6.36	17.2%
SOUTHERN	68.25	14.5%	23.91	35.0%
EASTERN	47.65	8.8%	3.11	7.5%
NORTH-EASTERN	167.54	35.5%	0.84	0.5%
TOTAL	472.15	100.0%	49.67	10.5%

TABLE - 04

INSTALLED CAPACITY

NORTH EASTERN INDIA

(AS ON NOV 1987)

STATE	THERMAL		HYDEL		DIESEL MW	TOTAL MW
	COAL MW	GAS MW	MAJOR MW	SMALL MW		
ARUNACHAL	--	--	--	13.42	6.10	19.52
ASSAM	240	242.4	--	2.0	23.27	507.67
MANIPUR	--	--	--	2.8	21.89	24.69
MEGHALAYA	2.5	—	114	12.71	1.95	131.16
MIZORAM	--	--	--	1.0	13.36	14.36
NAGALAND	--	--	--	1.5	3.62	5.12
TRIPURA	--	10.0	--	16.0	6.28	32.28
CENTRAL	--	--	155	--	--	155
TOTAL	242.5	252.4	269	49.43	76.47	889.80

TABLE - 05

SMALL HYDRO ELECTRIC SCHEMES

NORTH EASTERN INDIA

STATE	IN OPERATION		UNDER EXECUTION	
	NUMBER OF POWER STATIONS	INSTALLED CAPACITY KW	NUMBER OF POWER STATIONS	INSTALLED CAPACITY KW
ARUNACHAL	24	13420	9	9400
ASSAM	1	2000	2	24000
MANIPUR	4	2800	6	5100
MEGHALAYA	2	12710	-	--
MIZORAM	1	1000	2	900
NAGALAND	1	1500	1	1000
TRIPURA	3	16000	1	50
TOTAL	36	49430	21	40450

TABLE - 06

NORTH EASTERN INDIA
RURAL ELECTRIFICATION
(As on 31.03.88)

STATE	TOTAL NO. VILLAGES	VILLAGES ELECTRIFIED	PERCENTAGE VILLAGES ELECTRIFIED
ARUNACHAL	3257	1068	32.8%
ASSAM	21995	17897	81.3%
MANIPUR	2082	887	42.6%
MEGHALAYA	4583	1622	35.4%
MIZORAM	721	258	35.78%
NAGALAND	1112	1072	96.4%
TRIPURA	4727	* 2174	45.9%
N. E. REGION	38477	24978	64.9%
INDIA	576126	* 412018	71.5%

* As on 31.03.87

TABLE - 07

COSTS OF INSTALLATION

SCHEME	INSTALLED CAPACITY	COST OF INSTALLATION MILLION INDIAN Rs			VILLAGES SERVED	NETT HEAD	PER KW INSTLD COST	
		CIVIL	ELECT	TOTAL			INDIAN Rs.	US DOLLARS
SILLE	350 KW	3.0	2.8	6.0	5	70m	17,150	1270
JUGDI	1000 KW	5.1	7.6	13.1	13	450m	13,100	970
K'TANG	750 KW	5.8	9.5	15.7	20	279m	20,930	1550
MUKTO	1000 KW	6.7	8.2	15.4	5	230m	15,400	1140
SAGALU	1000 KW	8.6	10.0	19.3	18	56m	19,300	1430
C'TAJO	200 KW	2.9	3.3	6.4	17	90m	32,000	2370
SURBI	1000 KW	7.6	9.9	18.0	13	249m	18,000	1335
SIPIT	2000 KW	9.0	13.3	22.3	11	145m	11,150	825
GANGA	750 KW	--	--	30.3	Town	--	40,400	2995
KITHURI	90 KW	2.3	.06	2.9	3	40m	32,200	2390

TABLE - 08

SALIENT FEATURES

EXISTING SCHEMES

No. of Stations	-	25
No. of Sets	-	70
Total Capacity	-	19,450 KW
Head Range	-	20m to 200m
Set Ratings	-	10 KW to 500 KW
INSTALLED COST PER KW	-	US $.500.00 to US $.1000.00

Transferring Technology - A Social Marketing Perspective

By
S.D. Lhalungpa

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PRESENTATION

by

Samphe Lhalungpa
PASSMORE ASSOCIATES INTERNATIONAL

for

SMALL HYDRO'88

A Social Marketing Perspective

I would like to draw on six years of field experience with the U.N. as a Communications Officer in S.E. Asia and Sub Saharan Africa where I worked in the area of health promotion. You may well ask what public health has to do with small hydro. And the answer is :

If your interest is only in selling hardware. then I maintain that there is really little cross-over and it may be better to spend time with trade commissioners and trade directories.

However. given that small hydro offers itself as a small. community friendly. environmentally benign technology with considerable possibilities for decentralization. then I maintain that it may be useful for you to tap the body of knowledge and experience now available on development and technological transfer.

Development thinking has come a ways from the mechanistic notion that countries/societies developed when x amounts of inputs - usually financial and technical - were poured into a situation.

But the real world of people and communities soon confounded the plans of development planners and there was a growing realization that technology was not a neutral input. Increasingly. the question came to be asked: Development for Whom? Who benefits? Who pays the Costs?

The first system experience of technology transfer was in agriculture as countries sought to increase food production using scientific methods. It seemed so simple at first: inject sufficient amounts of equipment, supplies and personnel to the areas in question and watch as farmers adopted the obviously superior knowledge and technology to increase output. However, for every success of the green revolution - and even here the social costs in marginalisation of small landholders is an issue - there is a Sub Saharan example like the Sudan where the extension of tractor farming in the rain fed ranges of the west and the south have contributed to the desertification as agro-entrepeneurs tractor farm, take two crops and then leave the land bereft of what little top soil it had in the first place. Technology has not been universally beneficial.

The ideological basis for modernization was, at best, an enlightened paternalism with development priorities more often than not set by donor organizations or central governments with little regard for the communities affected.

Naturally, the communications efforts that characterized this phase - and it has by no means passed as a dominant paradigm - were top down and preachy in tone - the overworked index finger and knitted brow were pressed into service as extension agents and health workers scolded mothers, fathers, farmers, fishermen, on three continents for not following whatever it was that was specified - whether it was feeding their infants more nutritious foods or digging latrines or sending their children to school.

The mega projects so beloved by planners and donors created new structures, new problems and new dependencies. At the micro-level.the adoption of bottle feeding once sold to urban and rural poor as a modern and scientific advance probably resulted in the deaths of more babies than its advocates would like to admit. The poor had little access to clean water and other conditions necessary to practice safe bottle feeding. In addition, this practice took up an inordinate amount of the family's meager budget and deepened the poverty cycle. Breast-feeding, the natural, beneficial and practical alternative has always been there.

It is now realized that the easiest part of development process is the hardware procurement and delivery and that explains why this forms such a large percentage of development budgets. But increasingly, donors, governments, and academics are realizing that it is the software of development, that is the social factors, the level and kinds of organizations, the communications channels, and the training that makes the difference between one project succeeding and the next one not. As someone said, information is the difference that makes the difference.

In large measure development efforts have widened the existing inequalities between town and country, rich and poor, landed and landless. The new production technologies have made the creation of wealth easier for some and magnified the traditional gaps.

It was recognized that the methods that were used to change traditional feeding practises from breast feeding to bottle feeding could also be used to effect a change back to breast feeding or other socially beneficial objectives. This realization that the tools of marketing could be used to promote socially desirable ends is now characterized as Social Marketing.

According to Kotler, an early proponent of this approach, Social Marketing,"utilizes the concepts of market segmentation, consumer research, idea configuration, communication, facilitation incentives and exchange theory to maximize target - the preferred word is beneficiary - response."

Manoff, another proponent and practioner of Social Marketing says: "The developing world is scarred with inappropriate transfers of technology. Blame for Africa's food crisis has been ascribed by more than one authority to development models that fail to provide a convincing understanding of the motivations of rural people and the role of technological change....Development is a historical, social, political, technical and organizational process which cannot be understood by the means of a single discipline." The author then goes on to offer social marketing as a problem solving methodology relevant to the needs of the developing world. He cites:"Marketing is a rationale, a problem solving systems approach for institutionalising an idea, a product, a point of view, a public policy, a political party or a candidate...marketing is a neutral methodology and social marketing is an adaptation to public health or other social imperatives."

What is it in the Social Marketing process that distinguishes it from other communication approaches? Again to quote McGowan: "The key activity that makes the marketing concept work is marketing research...central to the task of marketing research is research in the product policies, pricing policies, distribution policies and promotion policies--those four basic factors in the marketing mix that are generally controllable by the firm. Research into the external and generally uncontrollable factors is also necessary for firms wishing to maintain a competitive market."

Let us briefly consider how these translate in a Social Marketing strategy where we are promoting the adoption or more correctly, the re-adoption of breast feeding.

Our product as such is the idea and practice of breast feeding. Our research should tell us what proportion of mothers breast feed and the reasons why they continue or have stopped this practice. As important, we need to know why mothers have changed over to other feeding practises. While there is no direct cost for breast feeding, there are other social costs among others the fear of being considered old fashioned, by ones peers. In terms of distribution, breast milk is universally available but there might be need for education on the kinds of foods mothers may need to eat to facilitate lactation.

Participation is a powerful idea which has now received the attention of the social scientists. There is more than enough evidence to show that where communities participated in projects they were more likely than not to be successful. There are some very pertinent examples from Nepal and the Philippines - selected because they are documented and not because they are particularly outstanding examples of official neglect.

Norman Uphoff cites a case from Nepal where a dam was being built. He writes: "Although this project was undertaken for the benefit of the local people they were little involved in its planning. When the time came for its implementation, the local people wanted to have it built on a stronger foundation...which was not included in its design and estimate so the request was not complied with....As it turned out, in the last monsoon, the dam gave in at the base, thus confirming the apprehension of the villagers."

Another scheme involving lift pumps and piped water supply to farms was based on electricity. Farmers said they would have preferred systems using gravity flow as they could manage the technology themselves. As the farmers feared, the water supply was interrupted whenever power was diverted to the capital. Moreover, the farmers pointed out that piping water to the fields did not allow the cold river water to warm in the sun as happens in traditional systems and the crops do not do as well because of the difference in the water temperature.

Farmers were given no voice in the decision but they paid a price.

In his "Fitting Projects to People". Uphoff makes a cogent case for peoples participation in development projects. He calls for the involvement of intended beneficiaries in decision making. implementation. evaluation and of course benefits.

In terms of development paradigms. the participation approach calls for a significant degree of self reliance from people. Participation is recommended as promoting the triad of efficiency. equity and empowerment. The case for the first has already been made with the two foregoing examples.

As the thrust of the marketing effort is the "consumer", it disciplines planners to design an organization's offerings in terms of the target market's needs and desires and on using effective pricing. communications and distribution to inform. motivate and service markets.

This viewpoint. I maintain. can be contrasted with the traditional. paternalistic and expert oriented view of development which basically sees rural communities as empty canvas on which new knowledge and structures can be applied.

Today we are much more aware of the rich tapestry of peoples lives, their belief systems and their agricultural practises. The attempt is not so much to displace traditional knowledge wholesale but to complement it. Of course, this requires a much more sensitive approach to development and innovation.

As a rule of thumb, I would say: Know your markets. Know your players too, not just the decision makers in the capital but those areas in the hinterland where there is potential for small hydro development. Examine what it is people are doing now to meet some of their power needs; look at the informal sector to assess the kinds of skills available in the area. Often times you will find official vehicles grounded for want of spares while privately owned pick up trucks and buses are kept running by local ingenuity. I learned from mechanics in Burma that when one has no brake fluid one makes up a very soapy solution instead. In both Burma and Thailand, I marveled at the way farmers in low lying areas converted the ubiquitous water pumps into the "long tailed" outboard engines. It is this spirit and the problem solving capacities it captures that need to be harnessed - too often the official channels are clogged or bogged down or rendered impotent by the weight of bureaucracy and the need to impose their ways of working on people.

Equity is now pursued as a goal as planners realize that development can actually increase the gap between the rich and poor both internationally and within countries. As for empowerment, social marketing can work because it empowers people with the knowledge and support to change their own lives. It is not an easy process but in the long run it may be the only sustainable approach which builds on involving people in their own destinies.

You will notice I have spoken very little of small hydro or a blue print for social marketing approach. However, I hope my discussion of the process of social marketing and the context in which development activities occur will help in setting project objectives and approaches. In communities looking for self reliance the promise of small hydro technology is its simplicity and cost effectiveness.

The premise of rural electricity should not perhaps be that every hut will have a light bulb but that the public spaces of the community - the health post. the school. the tea shop and the village church, pagoda or temple will have light. Used to power a radio or television it makes the village part of a larger knowledge network to both bring in new knowledge from the outside which can then be modified in the light of independent knowledge and experience.

Mimicry is no longer a guiding force in development. It is now realized that the development process throws up new terms that are the synthesis of old and new. Only the confident can create wealth.

Small Hydro in Canada - 1988

By
P. Fawkes

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SMALL HYDRO IN CANADA - 1988

Patrick Fawkes
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Presented at SMALL HYDRO '88
An International Conference and Trade Show
July 4-9, 1988
Toronto, Ontario

SMALL HYDRO IN CANADA - 1988

INTRODUCTION

There are more than 327 small hydro plants under 15 MW across Canada with a total peak capacity of 1,000 MW. Six more plants with a total capacity of 56 MW are under construction or committed for construction by the end of 1989. Does this level of activity provide a large enough market in Canada to encourage the development of a healthy small hydro industry in this country?

The paper presents an overview of present activity in small hydro (less than 15 MW), and comments on the prospects for future small hydro development in Canada.

In the context of this paper the small hydro industry includes manufacturers of specialized equipment such as turbines, generators, control equipment etc; manufacturers of equipment and materials not specifically made for small hydro, such as pipe, valves, transmission line cable etc; consulting engineers; entrepreneurs and developers who build plants to sell energy; and dealers in used equipment and materials.

OPERATING SMALL HYDRO PLANTS

To assess the level of activity of the industry, a list of operating small hydro plants (less than 15 MW) is shown in Table I. The list was assembled from information from Statistics Canada, EMR (Energy, Mines and Resource Canada), provincial power authorities/corporations, and provincial ministries of energy. Most of the existing plants are included, except perhaps some smaller plants with capacities less than about 20-30 kW.

Most of the recent construction started after 1980 which is about the time the federal government started programs to encourage growth in the small renewable energy industry: programs such as CREDA (Conservation and Renewable Energy

Demonstration Agreement), ENERDEMO and RCDP (Remote Community demonstration Program). Table I shows for each province the total installed capacity to the end of 1980 and lists individual plant data since that date.

The data are summarized in Table II to show the rate of development since 1980: 23,793 kW installed during the five year period 1981-85 - 4,760 kW per year; 35,613 kW installed during 1986-88 - 11,870 kW per year; and 56,000 kW committed for completion by the end of 1989.

Table III is more descriptive: 20 projects have been selected to show the diversity of project size and the variations in some of the features - it also shows the inventiveness of some of the owners of the smaller plants. Plant sizes vary from 5 kW to 15.5 MW (projects #7 and #20); an intake is simply a pipe lowered into the stream (#1), or an engineer designed concrete structure with gate and trashrack (#19); several types of turbines are listed - Francis, Pelton, Kaplan, crossflow, submersible turbine-generator units - as well as two home-built cross-flows and centrifugal pumps as turbines (#9); new, used, or refurbished turbines and generators are shown; new and old penstocks and powerplants are used; and generating equipment has been added to existing water supply dams (#10, #11).

Such a diversity of plant size and design of project features provide markets for different sections of the small hydro industry. For example, a plant less than 10 kW would probably be built by the owner, and would incorporate used equipment paid for with his own cash; there would not be much opportunity for the small hydro industry except possibly some electronic control equipment and a used turbine. However, for a 1 MW plant, all sectors of the industry would be involved: consulting engineers, a construction company, turbine and generator manufacturers, electric control manufacturers, etc.

Plant sizes less than about 20 kW are often not considered important because the dollar value to industry is small, and sometimes negligible. However, small hydro developments, like other small scale energy projects, provide opportunities for small firms to prosper away from larger centres of population, and often provide local employment close to the project, which is usually considered remote. Thus, the smallest plants are important in the social context though they do not have a significant impact on the industry.

SMALL HYDRO POTENTIAL

The total potential for small hydro sites in Canada less than 10 MW has been estimated as 2000 MW at more than 1000 sites (1). These figures were derived from ten inventory studies made for most provinces, and although different methods were used in each study for estimating site potential, it appears that development of 2000 MW is economically feasible. Thus the potential for small hydro is twice the total capacity of operating small hydro plants, and there is no constraint on development because of a lack of potential sites. However, there are other constraints on development, which are discussed later, such as present utility buy-back rates that many developers consider too low.

GOVERNMENT SUPPORTED DEMONSTRATION PROJECTS AND RESEARCH AND DEVELOPMENT

Since 1980 the federal government has supported the development of small hydro through demonstration projects, research and development of technologies, inventory and feasibility studies, and by sponsoring several conferences, workshops, and the publication of a manual and a newsletter. The major objectives of the federal government's support of small hydro are to help reduce the installation cost for existing technology, and to demonstrate new techniques and designs that have a reasonable chance for economic application (2).

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(1) Numbers in parenthesis refer to References listed at the end of the paper.

Demonstration Projects

Under several cost-sharing agreements with the provincies, including CREDA, ENERDEMO and RCDP the federal government has provided funds for the construction of 21 small hydro demonstration projects (3). "The purpose of the demonstration initiative was to establish the financial and commercial viability of small hydro while generating some industrial activity and putting some technical innovations into practice" (6). These demonstrations were new or redeveloped projects, ranging in size from 2 kW to 2.2 MW. The numbers in each province are:

Newfoundland	2
Nova Scotia	2
P.E.I.	1
New Brunswick	2
Quebec	2
Ontario	7
Yukon	1
British Columbia	4

Total projects costs were $ 15.2 x 10^6, of which approximately $ 3.4 x 10^6 was contributed by the federal and provincial governments. All these projects are included in Table I. Most of them have been described in Project Summary sheets published by EMR, one in a report (4), and several projects have been discussed in papers (2,3) and in Small Hydro News Canada (5).

Research and Development

The extent of Federal government contributions to small hydro R & D has been described in the paper in this conference, "Technology: Strategy for Small Hydro", and in other papers (2, 6, 7) and in SOL magazine (8).

Eleven contracts for R & D projects related to small hydro were awarded in 1986 and thriteen more in 1987. The number of projects in each of four categories, and federal government contributions are shown below:

Category	Number of Projects	Total Project Value	Total EMR Funding
Turbine and Generating Equipment	17	1,529,000	873,000
Civil Works and Components	4	322,000	304,000
Site Assessment and Environment	3	216,000	86,000
Technology Transfer	1	14,000	14,000
TOTALS	25	2,081,000	1,277,000

Tidal power R & D has also been supported by the federal government, but it is not considered applicable to small hydro.

The major part of federal government funding has been for development of improved and cost-effective turbines, generators and automatic control equipment. However, for a small hydro project the turbine, generator, and control equipment typically account for 20-30% of the total cost, whereas the civil works, including dam, intake, penstock and powerhouse structure normally account for 30-70%. These figures indicate that more emphasis should be put on developing and demonstrating innovative designs to reduce civil works costs. For example prefabricated intakes and powerhouses could reduce the cost of installation for projects where access is difficult or where the plant has to be reused in another location several years after the initial installation e.g. for a small logging operation or mine. Also, it has been suggested (2) "there is a need for innovative conceptual design for developing low-head mini-hydro on a relatively wide river", where construction of a long dam or weir could make the project uneconomic.

OTHER ACTIVITIES EFFECTING SMALL HYDRO DEVELOPMENT

Information Exchange

The dissemination of information - technical, financial and regulatory - to prospective builders or developers of small hydro is an important activity in encouraging small hydro development. Workshops and courses have been arranged by EMR in cooperation with provincial ministries and power utilities: for example, the Small Hydro Engineering Course held in conjunction with the Small Hydro '86 Conference in Toronto; Small Hydro Canada '87 in Burnaby, B.C.; Small Hydro Short Course and Workshop given at four locations throughout B.C. in 1987/88; and the two educational courses preceding this conference. The handbooks published for these courses provided useful reference material for most aspects of small hydro development, such as: technical information on all aspects of designing and building a project; provincial regulations; utility purchase rates and regulations; and examples of construction methods suited to developing countries to maximize the use of indigenous resources and expertise.

Open discussion of utility buy-back rates has been encouraged recently at two workshops: the Parallel Generation Workshop '87 organized by Ontario Hydro in Toronto in October 1987; and the Electrical Energy Forum sponsored by B.C. Hydro and the B.C. Ministry of Energy Mines and Petroleum Resources in Vancouver in June 1988. In both workshops Hydro's policies, connection requirements, power purchase rates and purchase agreements were presented by Hydro staff, and discussed by non-Hydro speakers. These forums provided opportunities for private power producers to present their views on these subjects, particularly on power purchase rates which they generally considered to be too low to encourage parallel generation.

Detailed information on provincial policies, utility power purchase rates and regulations were provided in the course "Small Hydro Project Development in Canada" which preceded this conference.

Private Power Producers Associations

With the growing opportunities for parallel generation, private power producers are forming associations to focus their concerns and to make presentations to provincial ministries, public utility commissions and provincial power utilities.

Associations have been formed in Ontario and Alberta, and are in the process of forming in B.C. and Nova Scotia.

In October 1987 the Small Power Producer's Association of Alberta (SPPAA) made presentations at a Small Power Inquiry that considered how small power facilities could best be developed for the benefit of the consumer.

Also, in December 1987, private power producers in Nova Scotia intervened against a proposed work order by Nova Scotia Power Corporation (NSPC) to build a 150 MW coal-fired plant, because the interveners contended that NSPC hadn't fully investigated alternatives to the coal-fired plant, in particular the private power option.

SMALL HYDRO INDUSTRY IN CANADA

Two surveys of the Canadian small hydro industry have been made recently: one surveyed a sample of companies across Canada to identify their capabilities with special attention to international market experience - the survey was part of a background study for this conference (9) and has been discussed during the opening plenary session; another study surveyed only B.C. companies, and was part of a study of the probable effects of deregulation of electricity production and distribution in B.C. (10). The Canadian survey was based on 52 companies, of which 35 percent were turbine or generator manufacturers, about 20 percent were engineering consultants and the remainder were in financing, construction, or other equipment manufacturing. The companies were capable of providing a broad range of manufactured products and services, for a full range of project size from less than 10 kW up to 10 MW. However, there was a lack of exposure to international markets. The United States was the biggest export market, and when this market was excluded, Canadian firms could not be considered serious participants in the international small hydro marketplace (9).

In the B.C. study (10) 23 companies were surveyed: about 35 percent were small hydro-related manufacturers (turbines, generators, switchgear, governors), 17 percent were manufactures of non-specialized equipment (pipes, electrical equipment etc.), and 48 percent were engineering consultants. This was considered to be a representative sample of companies active in the small hydro industry. However, only a few companies said that small hydro comprised more than 10% of their total gross revenue. These firms were generally involved at all levels in the industry e.g. research, development, and specialized equipment suppliers, and sold products or services outside B.C., in Canada, and in foreign markets. Again, the U.S. market was the most important.

PROSPECTS FOR FUTURE SMALL HYDRO DEVELOPMENT IN CANADA

With 327 operating plants and 6 under construction (total 1,056 MW) considerable experience in project design and manufacture of equipment has developed in Canada. The total potential capacity of small hydro sites is about twice the existing small hydro capacity. However, the amount of small hydro actually developed in the future will depend to a large extend on the policies and power purchase rates that apply to parallel generation, i.e. private power generation purchased by provincial power utilities. This is because parallel generation offers the greatest opportunities for development of small hydro in the future. In B.C., the study made in late 1987 (10) assessed the expected development of small hydro under alternative B.C. Hydro (BCH) private power purchase rates. Assuming a rate of 3.2¢ /kW.h based on an avoided cost formula, an estimated 174 sites, with total capacity of 742 MW, could be developed.

In June 1988 BCH presented a draft policy on purchase of electricity from parallel generators (11). For projects less than 5 MW BCH will pay between 2.5¢ /kW.h and 3.0¢ /kW.h (in 1988). These prices reflect Hydro's short-term and long-term marginal costs. The actual price will be set by 1 October 1988 and will be adjusted annually, indexed to changes in BCH's marginal costs. We will have to wait till October to see how private power producers react to the set price.

Ontario Hydro has an established parallel generation policy, with purchase rates of 3.76¢ /kW.h for monthly capacity factors 65% or greater, and 2.54¢ /kW.h for capacity factors below 65%. These and previous Ontario Hydro rates have encouraged 22 small hydro parallel generators to build a total capacity of 14.5 MW up to March 1988, and another 10 plants totalling 17.1 MW are committed for in-service by the end of 1989. This indicates that the purchase rates and other aspects of the purchase agreements are generally acceptable to the parallel generators.

Two recent announcements could effect the future of small hydro:

1) The Nova Scotia Power Corporation (NSPC) will consider proposals from private power producers (hydro and woodchip) for the supply of up to 30 MW to be made up of several projects. The Board of Commissioners of Public Utilities will establish the price to be paid for private power based on the full avoided cost to NSPC. (announcements made May 19, 1988)
2) In the fall of 1988 B.C. Hydro (BCH) expects to issue a Request for Proposals for 100 MW to 200 MW of parallel generation for the integrated system. Also, in the spring of each year BCH proposes to accept up to 25 MW in blocks of less than 5 MW. (announcement made June 10, 1988)

Although these changes in policy will not have an immediate effect on small hydro development, they show an increasing acceptance across Canada that parallel generation can help delay construction of major power developments, to the benefit of the utility and the consumer.

This overview of the small hydro scene in Canada indicates that a modest small hydro-related industry exists, which is capable of providing design services and manufactured products to meet the present and expected near future level of activity. The industry will grow only when more provincial power utilities offer private power producers purchase rates which allow those producers to make a reasonable profit.

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TABLE I -- SMALL HYDRO PLANTS IN CANADA LESS THAN 15 MW

Plant Name	Owner	Capacity kW	In Service Date	Cost $x1,000	Notes
Newfoundland					
Total end 1980:	25 plants	94,430			
Roddington	Nfld. & Lab. Hydro (NLPC)	440	1980	1,225	D
Topsail	(NLPC)	+1,300	1984	1,750	
Lawn	(NLPC)	+ 350	1984	1,400	
Morris	(NLPC)	1,050	1984		
Mary's Harbour	Mary's Harbour Hydro	135	1987	625	D
Total end 1988:	28 plants	97,705			
Prince Edward Island					
Breadalbane Dam		3.5			D
Total end 1988:	1 plant	3.5			
Nova Scotia					
Total end 1980:	31 plants	142,420			
Black River	N. Livingston	5	1980	22.8	D
Fourth Lake	N.S. Power Corp.	3,100	1983		
Margaree Forks	J. Watkins	10	1983	3.4	D
Melford Brook	N. Livingston	225	1984		
Fall River	N.S. Power Corp.	500	1985		
9 plants (1-15 kW)		51	1981-85		
Total end 1988:	45 plants	146,311			
New Brunswick					
Total end 1980:	8 plants	36,790			
Green River	City of Edmundston	2,000	1985	2,510	D
McCrea Farms	L. McCrea	31	1987	80.4	D
Total end 1988:	10 plants	38,821			
Quebec					
Total end 1980:	46 plants	173,370			
Maquatua	Wemindji Band	1,100	1985	6,500	D
Penman	City of Coaticook	600	1986)		
Saint-Paul	City of Coaticook		)	1,300	D
		520	1986)		
Buckingham	ERCO (Tenneco)	+ 1,057	1987		
Lachute	Ayers Ltd.	5,100	1987		
Eustis	City of Sherbrooke	+ 460	1987		
Cascades Savard	L. Savard Inc.	50	1988	130	D
Cote St. Catherine	Hydromega Inc.	2,000	1988	3,156	D,P
Riviere-du-Loup	Mohawk Pulp	340			
Chemin du Lac	Mohawk Pulp	200			
Ruisseau Vassale	Mohawk Pulp	20			
Riviere Noire	Mohawk Pulp	10			
Total end 1988:	52	177,889			

Plant Name	Owner	Capacity Kw	In Service Date	Cost $x1,000	Notes
Ontario					
Total end 1988:	72 plants	330,280			
Wasdell Falls	Ontario Hydro	145	1980	1,291	D
Sandman	F. Sanders	8	1980		
Beeler Farm	A. Beeler	20	1980		
Sultan	Ontario Hydro	150	1982	1,522	D
St. Jacobs	St. Jacobs Mill	75	1982		
Laurentian Ldg.	Laurentian Lodge	30	1982		
Guelph Dam	Grand River Conserv. Auth.	150	1982		D,P
Millcroft Inn	Millcroft Inn Ltd.	24	1983		D
Elora Mill	Elora Mill	130	1984	300	D
Fanshawe Dam	Upper Thames R. Conserv. Auth.	500	1984	836	D,P
Peterborough	Peterborough PVC	220	1984	262.8	D
Thornbury Dam	H.von Teichman	135	1984	295	D,P
Homedale	Brantford PVC	115	1984	442	D
Wilsons Mill	J. Wilson & Sons	95	1984	56.0	D
Galetta G.S.	Galetta Power Ltd.	800	1984		P
Hurdman Dam	Marsh Hydro-power Inc.	600	1984		P
Dorian Fish Hat.	Dorian Fish Hatchery	16	1984		D,P
Frontier Lodge	Frontier Lodge	80	1984		D
Prairie Portage	Min. of Gov't Serv.	18	1984		D
Dowmanville	Vanstone Mill	58	1984		
Arnprior	N. Fraser	50	1985		P
Kuiper G.S.	R. Kuiper	110	1985		P
Kinsmen Park	Kinsman Club	200	1985		D
Pittens Farms	Pittens Farms Ltd.	40	1986		P
Glen Miller	Marsh Hydro-power Inc.	1,200	1986		P
Burks Falls	Burks Falls Waterpow.	1,000	1986		P
Scone	Saugeen Power Co.	70	1986		P
Eagle Lake	Sundridge P. C.	3,000	1986		P
Wainright	Sundridge P.C.	1,000	1986		P
Boulevard Lake	Current R Hydro	530	1986	653	P
Shand Dam	Grand River Conserv. Auth.	690	1987		P
Casselman	Casselman Small Hyd.	375	1987		P
Douglas	Galleta Power Ltd.	325	1987	370	P
Rideau Falls	Rideau Falls Gen.	2,000	1987		P
Black River	635294 Ont. Inc.	490	1987		P
Scarfe Lake Dam	Scarfe Lake Elec. Co.	2,000	1987		P
Tweed		500	1988		P
Chesley		70	1988		P
South Saugeen R		80	1988		P
South Saugeen R		500	1988		P
Rocky Saugeen		600	1988		P

Plant Name	Owner	Capacity Kw	In Service Date	Cost $x1,000	Notes
Kagawong		700	1988		P
South River		1,700	1988		P
Port Dalhousie GS	St. Catherines Hydro. Comm.	6,750	1988		P
Trent Dam No. 1	City of Trenton	1,410	1988		
Total end 1988:	117 plants	359,039			
South River		1,000	1989		P
Cutler		6,000	1989		P
Montreal River		6,000	1989		P
Steephill Falls	Great Lakes Power	15,500	1989		
Magpie Falls	Great Lakes Power	12,500	1989		
Mission Falls	Great Lakes Power	15,000	1989		
Total end 1989:	123 plants	415,039			
Manitoba					
Total end 1988:	2 plants	10,350			
Saskatchewan					
Total end 1988:	3 plants	22,560			
Alberta					
Total end 1988:	5 plants	32,900			
British Columbia					
Total end 1980:	15 plants	72,610			
Treth Creek Plt.	McCall Enter. Ltd.	50	1980	40	
Kleimtu	Kitasoo Hydro Ltd.	320	1981		
Weston's Mill	G. Weston	90	1981	30	
Hoeya Hilton	Hoeya Hilton Resort	35	1982	39	D
Nimmo Bay	Nimmo Bay Resort	35	1982	46	D
3 Valley Gap	G. Bell	150	1982	290	
Kingcome Plant	Tsawataineuk Band	75	1982		
Glacier Park	Northlander Lodge	150	1983	330	D
Hasty Creek		37	1983	19	D
Rendell Cr.	Rendell Cr. Ranch	150	1983		
8 plants: 6-60 KW		186			
Phillipps Creek	McDonald Ranch & Lum.	400	1984	82.8	
Thelwood	Westmin Resources	8,100	1984	21,000	
Douglas	Indian & N. Affairs	30	1984	128	
Skookumchuck	Indian & N. Affairs	30	1984	150	
Eberts Cove	Crown Forest Ind. Ltd.	90	1985		
Tarrant Creek	Whonnock Ind.	60	1987		
Total end 1988:	39 plants	82,598			

Plant Name	Owner	Capacity Kw	In Service Date	Cost $x1,000	Notes
Yukon					
Total end 1980: 3 plants		6,750			
Carcross Rd.		1.6	1985	15	D
		10			
Total end 1988: 5 plants		6,762			
North West Territories					
Total end 1988: 4 plants		25,360			

Notes

D = Demonstration project: funding from federal and/or provincial governments.
P = Parallel generator: private power generator supplying a utility.

Example: +1300 means 1300 kW added to existing plant.

TABLE II EXISTING PLANTS LESS THAN 15 MW - SUMMARY

	Number of Plants	Capacity Range	Average Capacity	Total Capacity
Total at end of 1980	217	240 - 15,000	4,450	947,820
Additions 1981-85				
Newfoundland	4	350 - 1,300	785	3,140
Prince Edward Island	1			3.5
Nova Scotia	14	1 - 3,000	278	3,891
New Brunswick	1			2,000
Quebec	1			1,100
Ontario	23	8 - 800	162	3,729
British Columbia	23	6 - 8,100	432	9,928
(excluding 8100 kW plant)	(22	6 - 400	83	1,828)
Yukon	1			1.6
Total additions 1981-85	68	1 - 8,100	349	23,793
Additions 1986-88				
Newfoundland	1			135
New Brunswick	1			31
Quebec	11	10 - 5,100	941	10,357
Ontario	22	40 - 6,700	1,140	25,030
British Columbia	1			60
Total additions 1986 - 88	46	10 - 6,700	774	35,613
Total at end of 1988 (4 plants closed in Quebec during 1980-88)	327	1 - 15,000	3,059	1,000,299
Additions 1989 (committed)				
Ontario	6	1,000 - 15,500	9,330	56,000

TABLE III EXAMPLE OF PROJECT FEATURES

	Project Feature	Plant Name	Capac. kW	Head m	Cost $/kW	In-Service Date	Notes
1	Simple Intake	Weston Mill B.C.	90	41	333	1981	Pipe lowered into stream
2	Prefabricated steel intake	Tarrant Cr., B.C.	60	34		1987	Reuseable at another site
3	Prefabricated power plant	Wasdell Falls Ontario	145	3.7	8900	1980	Prototype Barber Mini Hydel; Vertical Francis turbine
4	Prefabricated power plant	Tarrant Cr., B.C.	60	34		1987	Steel box; cross flow turbine
5	Prefabricated power plant	Parmenter B.C.	10	9	2320	1980	James Leffel Hoppes; vertical propeller
6	Home made turbine	Rocky Mtn. Trout B.C.	10	60	1930		Crossflow
7	Home made turbine	R. Solomon Nova Scotia	5	100	3200	1983	Modified jet engine gas turbine
8	Submersible turbines	Coaticook Quebec	2 x 260	8.5	1160	1986	
9	Pumps as turbines	3 Valley Gap	150	33	1900	1982	12",14" & 16" used pumps from pulp mill
10	Turbines added to existing dam	Shand Ont.	690	19	1200	1987	Verticle Howden-Galt turbine added between spillway gates
11	Turbines added to existing dam	Fanshawe Ont.	400	12	2090	1984	Cross flow turbine; penstock added to existing disch. pipe
12	Syphon penstock	Wasdell Falls, Ont.	145	3.7	8900	1980	Syphon over existing dam; Mini Hydel turbine-gen. unit
13	Syphon penstock	Holmedale Ont.	150	3.6	2900	1985	Syphon over existing dam; turbine above headpond level
14	Kaplan turbines	Almonte Ont.	2x1100	9.1		1988	New turbines in 1925 powerhouse
15	Old Francis + new runner	Kagawong Ont.	700	30		1988	New runner in old Francis scroll case

	Project Feature	Plant Name	Capac. kW	Head m	Cost $/kW	In-Service Date	Notes
16	Old turbine reconditioned	Peterborough Pumphouse Ont.	200	3	1190	1984	1908 Samson vert. turbine recond.; gearbox & generator added
17	Plant refurbished & connected to grid	Wainwright Falls Ont.	1044	9		1987	Built 1921; gen. rewound; new transform elec. equip. added for interconnect
18	Pit turbines (fixed blade)	Port Dalhousie Ont.	2x3380	3.7		1988	4.0 m dia. horiz. turbines
19	New plant for remote community	Maquatua Que.	1100	10	6360	1984	Concrete dam & power house; horiz. prop. turbine; access: winter road or barge in summer
20	Kaplan turbines (vertical	Magpie River Ont.	15500 12500 15000	41 30 36		1989 1989 1989	

Developing Nepal's Small Hydro Resources: Problems and Prospects

By
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Developing Nepal's Small Hydro Resources: Problems and Prospects

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Introduction:

This paper examines the Nepali small hydro experience to date. The paper focuses on the set of government administered small hydropower (SHP) projects, though privately-owned micro hydro projects (MHP) will also be briefly discussed. The paper reviews the small hydro potential in Nepal and the current set of problems with planning, constructing and operating SHP installations. The setting for SHP projects is examined to make explicit the problems of the rural areas in which the SHP technologies are deployed. The central hypothesis of this paper is that the potential for the development of SHP resources in Nepal (and elsewhere in the Third World) depends very much on it's applications, the adaptability of those applications to rural conditions and cultures, and it's ability to achieve positive economic returns. A village-scale simulation model, which is used to project the impacts of a hypothetical SHP installation, was developed by the author and is outlined in the last section of this paper.

A Geographic Orientation of Nepal:

Figure One shows the locations of the three physiographic regions of Nepal. The High Himalayas generally parallel the northern border with Tibet (China), and the Mountain Region includes all areas above 3000 meters elevation. The Mountain Region is sparsely populated relative to the neighboring Hill Region (600 - 3000 m), where over half of the nation's population resides. Although the Hill Region is densely populated, there are very few motorable roads in this area due to the rugged and vertical terrain. The Lower Hills (Siwaliks) and the Terai Region are lowland areas (below 600 m) that delimit the northern extension of the Ganges Plains. The major river systems of Nepal are sourced in the glaciers of the Himalayas. Each flows in a southerly direction, through Hill Region, across the Terai, and eventually joins the Ganges or Brahmaputra Rivers.

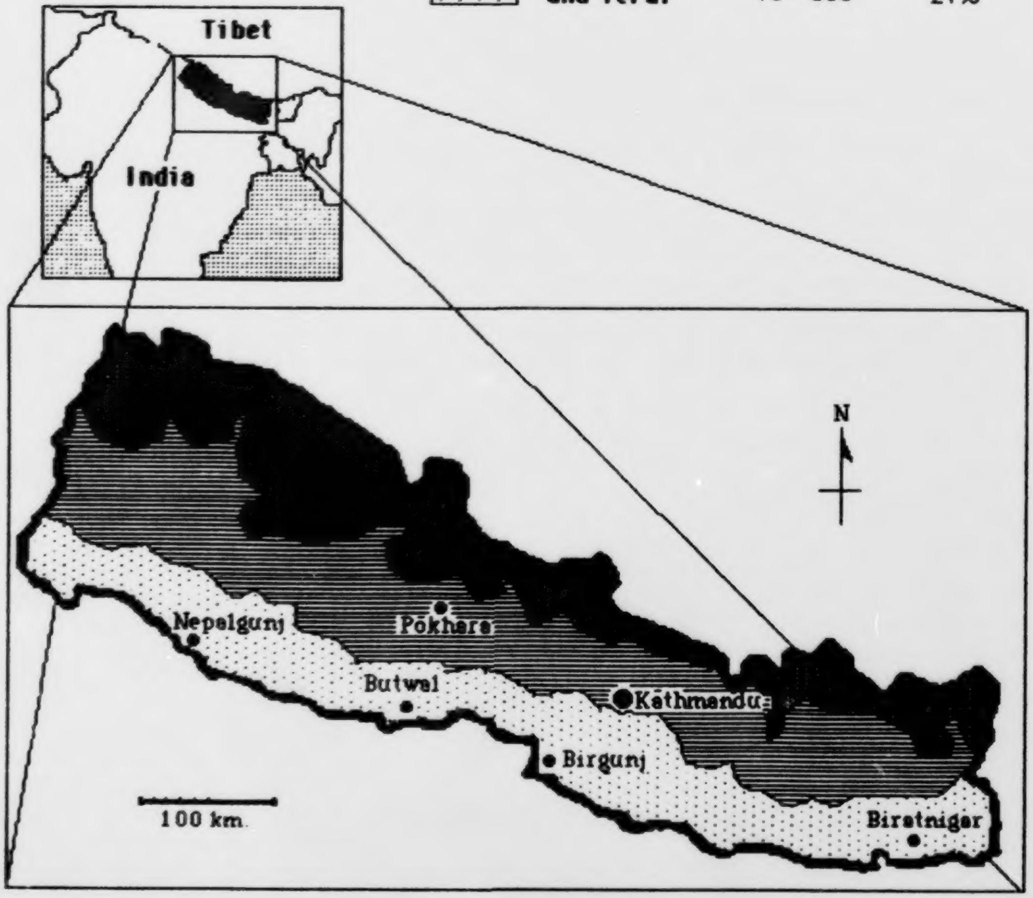
The nation is broken down into five Development (administrative) Regions which are oriented east to west, each including segments of the three physiographic regions. The Development Regions are further broken down into a hierarchy of districts, panchayats and individual villages. Kathmandu, the economic and administrative center of Nepal, has a population of approximately 250,000 against the national population of 17 million. Most of the urban areas in the country are found in the Terai Region. Both the road network and the centralized power grid of Nepal are limited to the lowland areas, and generally service only the larger urban centres. Overall, the urban population is relatively small at around 7% of the total population, though it is growing rapidly. However, approximately 90% of Nepal's population is presently engaged in subsistence agriculture, and rural populations are generally isolated from urban-commercial markets. As nearly all of the existing small hydro installations are located in the rural areas of the Hill Region, the following discussion examines some of the basic characteristics of subsistence agriculture economies in the Hills.

The Environmental Setting for Small Hydro Resources:

In order to understand the setting for SHP in Nepal, it is necessary to examine some of the more general characteristics of the rural environment of the Hills. Although there is as high degree of heterogeneity in the ethnic, agricultural and socio-economic characteristics of villages in the Hill Region, there are some general features which are common to most villages in this region. Hill villages generally lack developed cash economies, whereas bartering and the use of foodgrains as a

Figure One: A Map of the Physiographic Regions of Nepal

	Region:	Approximate Elevation Range (meters):	Percent of Total Area.
■	**High Himalaya (mountain)**	> 3000	23%
▤	**Hills**	600 - 3000	50%
░	**Lower Hills and Terai**	75 - 600	27%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Pokhara
Kathmandu
Butwal
Birgunj
Biratnigar
100 km.

medium of exchange is far more common. Land and livestock ownership are the primary measures of wealth. Due to the lack of a developed transport infrastructure, there are no mechanized agricultural technologies and commercial fertilizers are generally not available. Nearly all of the transport of goods in the Hill Region is carried by foot or by pack animals.

The Hill and Mountain Regions exhibit an exceptionally rugged terrain and unstable geology. Yet, the subsistence agriculturalists manage to harvest enough foodgrains from terraced agricultural plots to support rural populations. Terraced plots are found on slopes of up to 40°, though were population pressures are particularly accute, agricultural plots are found on still steeper slopes. The monsoon season lasts from mid-June to mid-October, and it is at the end of this season that the major harvests occur. Agricultural activity diminishes considerably during the longer dry season, though the use of gravity-fed irrigation systems allows for additional harvests of foodgrains. A primary role of livestock is as a labour resource for plowing and harrowing cultivated land. Livestock also provide dung, an extremely important resource used for fertilizing agricultural land. Dung can also be used as a cooking fuel, though fuelwood is the principle household fuel throughout Nepal.

Fuelwood accounts for approximately 90% of all energy consumed in Nepal (excluding human and animal labour). The collection of fuelwood is becoming an increasingly time-comsuming task as deforestation is now rampant across the country. Due to rapid population growth, the sustainable supply of fuelwood has been far outstripped by the current demand. Nepal's forests are essentially being mined as a non-renewable resource and most estimates point to a virtual exhaustion of forest resources shortly after the beginning of the next century. In short, Nepal is quickly depleting its primary energy resource. In the short-run, this will mean that dung will be used as a substitute for fuelwood, thereby resulting in reduced agricultural yields. Declining agricultural yields have lead to the expansion of agricultural land through forest clearing and terracing on steeper unstable slopes. In turn, these practices have lead to higher rates of soil erosion and an increase in the incidence of landslides.

Where there was once a fairly stable system of subsistence agriculture, rapid population growth has upset a delicate environmental equilibrium and many village environments are now headed toward a state of ecological collapse. The long-term implications of this crisis are rather grave given the proportion of Nepal's population that is engaged in subsistence agriculture. With on-going environmental degradation, it is reasonable to assume that the environment of the Hill Region will not be able support the population that presently inhabits this area.

The Hydro Potential In Nepal:

The hydro potential in Nepal is extremely vast, and hydraulic energy is considered to be the nation's most precious indigenous resource. The height of Himalayas and the relatively short distance to the lowland areas translate into high average stream and river gradients. These physiographic conditions mean that there is a wealth of sites with high potential heads for hydro projects at any scale. Yet, the essential question is whether or not small hydro can be developed to the extent that will provide for future energy needs in the Hill Region and for the nation as a whole. More specifically, can hydro power be used in a way that may reverse the accelerating trends of deforestation, declining agricultural yields, and environmental degredation.

A commonly quoted estimate puts the theoretical hydro potential at 83,000 MW though this estimate does not include all the rivulets and streams that could be tapped by small and micro-hydro projects. 50-70% of this theoretical potential is considered to be 'technically developable', whereas 30% of this potential (or 25,000 MW) is considered to be 'economically viable'. Yet, less than 1% of the theoretical potential has been tapped by all large, small and micro hydro projects.

Due to the rugged terrain and problems of accessibility and transport, storage resevoirs are difficult and costly to construct. Hence, most large and small-scale hydro installations in Nepal are run-of-the-river schemes, and the extreme seasonal variability of streamflows presents one problem for developing the hydro potential at both large and small-scale project sites. There is also a lack of reliable meteorologic and hydrologic data for individual watersheds in Nepal, though the following figures indicate what a flow duration curve might look like for streams and rivers. For the major glacially-sourced river systems, the ratio of maximum to minimum streamflows is on the order of 60:1. For rivers sourced below 2000 m, this ratio can be as high as 30,000:1. The monsoon (4 month) discharge accounts for as much as 80% of total annual discharge from all of Nepal's rivers.

The Development of Small and Micro Hydro Resources:

Hydropower is not a new technology in Nepal, as about 25,000 of the traditional 'pani ghattas' (water driven grain mills) operate throughout the Hill Region. Yet, only in the past two decades have more efficient small-scale hydro technologies been introduced in Nepal. Before discussing either the small or micro hydro resources, it is necessary to differentiate between these two technologies. The most important distinguishing features of Small Hydropower (SHP) projects are that they are government controlled projects used exclusively for village electrification. In contrast, Micro Hydropower (MHP) projects are privately owned, government financed projects used primarily for agro-processing. MHP facilities are beginning to be used to drive electric generators for local household lighting when the mills are not operating in the evenings. MHP generating capacities fall below 100 kW, and they are typically in the 10 to 30 kW range. The generating capacity of SHP installations generally range between 100 to 1000 kW, though some SHP projects have installed capacities as low as 32 kW.

Since their introduction in 1975, MHP projects have flourished across the Hill Region. Table One shows both the number of MHP projects that have been developed (between 1975 and 1985), and the projected number of projects that are expected over the next five years (to 1990). Overall, 1300 MHP projects are expected to be in place by 1990. The rapid diffusion of the Micro hydro technology can be attributed to a number of factors. MHP projects are used to operate grain processing mills and oil extractors, and village farmers have been quick to recognize that MHP installations represent a savings in both labour and time and over the traditional agro-processing technologies. Nearly all of the hardware for MHP projects is manufactured within Nepal, and manufacturers have been particularly concious of designing appropriate MHP systems for the Hill environment. Most MHP units are manufactured as integrated turbine and mill assemblies that are easily transported to sites by porters or pack animals. The other major factor to the success of MHP in Nepal is cost. Manufacturing, transport and import costs are substantially reduced by the domestic manufacturing capability. Most MHP projects have been implemented at a cost of between $US 5,000 to 12,000. The Agricultural Development Bank of Nepal (ADB/N) finances MHP projects on favourable terms of ammortization, and very few MHP project owners have defaulted on their loans. The ADB/N also provides an elaborate rural network of operation management services for MHP and other rural development projects.

In total, there are 10 SHP installations which have been completed, and 17 projects are under construction (some of those under construction may have been completed in the past year). The mean installed capacity of the 27 existing SHP plants is around 210 kW, whereas the total generating capacity of these plants is expected to be 5.4 MW. Figure Two provides a map of Nepal's SHP installations, and it can be seen that nearly all of the projects are found within the Hill Region. All of the SHP projects are remote facilities (off-grid), due to the prohibitive capital costs of extending grid transmission lines into the Hill Region. Figure Three shows the spatial extent of the centralized power grid, and it can be seen that the grid is confined to the lowland regions of the country. In short, it is unlikely that any of the existing SHP plants will be connected into the grid system in the near future.

The Small Hydel Power Department (SHPD) of the Nepali Government oversees the planning, construction and operation of all SHP projects, though projects are typically jointly funded by an international donor agencies and the Nepali Government. The SHPD chooses the location of projects based on the following siting criteria adopted by the Nepal Electricity Authority:

Table One: Estimates and Projections of Micro Hydro Units (1975-1990)

Year	Total Installations:	Financing Institutions: ADB/N*	Financing Institutions: Other
Estimates:			
1975	1	-	1
1976	1	-	1
1977	2	-	2
1978	9	3	6
1979	19	18	1
1980	21	19	2
1981	16	12	4
1982	55	46	9
1983	58	47	11
1984	74	62	12
1985	91	81	10
Total	347	288	59
Projections:			
1986	120	100	20
1987	120	100	20
1988	240	150	90
1989	240	150	90
1990	240	150	90
Total	960	650	310

* ADB/N - Agricultural Development Bank of Nepal

Source: G.R. Shrestha (1985)

Table Two: Capital Requirements for the Electrical Power Sector (1982-90)

(in million 1982 US$)

	Period: 1982-84	Period: 1985-87	Period: 1988-90	Totals: (%)
Centralized Grid System				
Generation Projects	217.3	505.6	203.0	925.9 (74.1%)
Transmission	77.3	91.4	126.0	294.7 (23.6%)
Small Hydro (remote)	8.5	4.1	-	12.6 (1.0%)
Micro Hydro (remote)	10.6	5.8	-	16.4 (1.3%)
Totals	313.7	606.9	329.0	1249.6 (100%)

Source: Smith (1983)

Figure Two: Small-Scale Hydroelectric Installations of Nepal

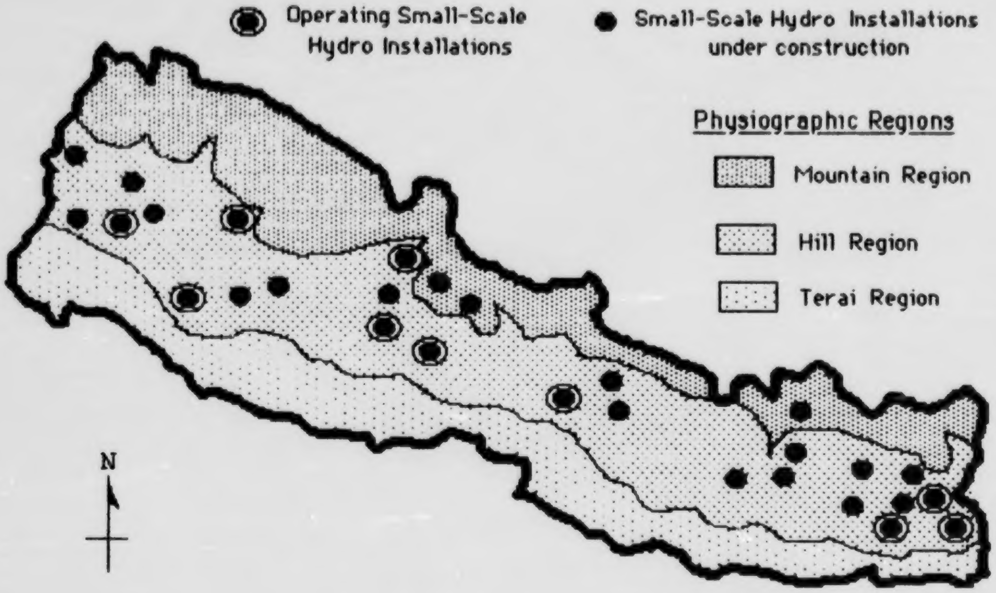
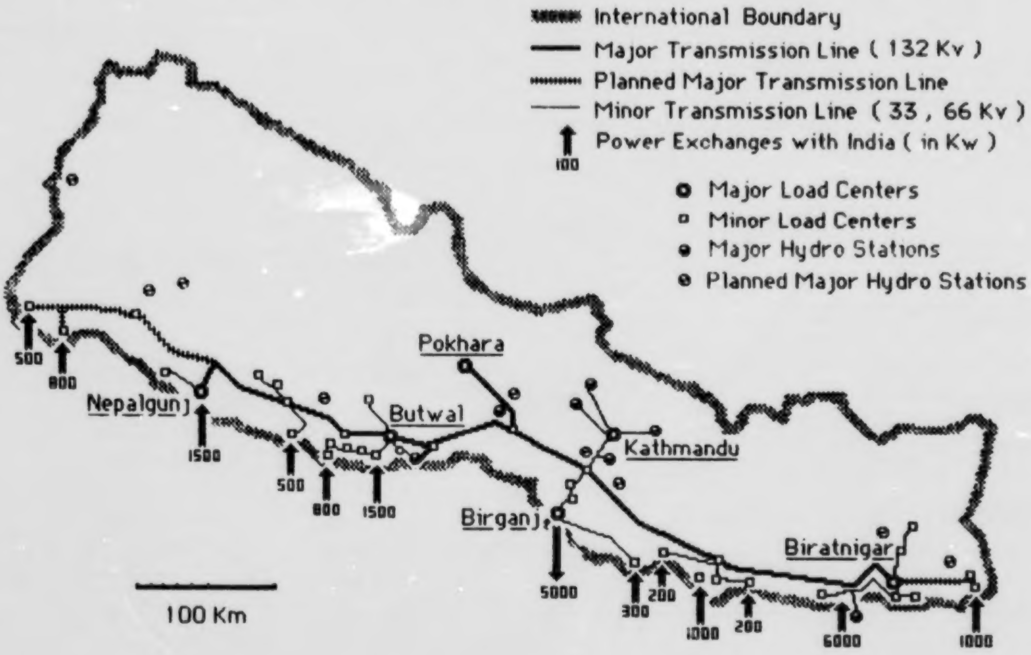

Operating Small-Scale Hydro Installations
Small-Scale Hydro Installations under construction
Physiographic Regions
Mountain Region
Hill Region
Terai Region
N

Figure Three: The Centralized Electrical Power Grid of Nepal


International Boundary
Major Transmission Line (132 Kv)
Planned Major Transmission Line
Minor Transmission Line (33 , 66 Kv)
Power Exchanges with India (in Kw)
100
Major Load Centers
Minor Load Centers
Major Hydro Stations
Planned Major Hydro Stations
Pokhara
Nepalgunj
Butwal
Kathmandu
Birganj
Biratnigar
500
800
1500
500
800
1500
5000
300
200
1000
200
6000
1000
100 Km

1. District Headquarters
2. Multipurpose Projects (i.e. irrigation and water supply)
3. Villages with Cottage Industries
4. Places of Tourist Interest

In fact, the first of these is the sole criteria by which small hydro sites are chosen. All SHP projects have been implemented in district headquarters, and this reflects a strong political dimension to the siting of SHP installations. This is unfortunate given that district headquarters are by no means the most economic SHP sites.

Table Two specifies the capital requirements of the Electrical Power Sector (1982-1990), and it can be seen that the capital slated for the development of both SHP and MHP amounts to only 2.3% of the total. This finding indicates an obvious expenditure bias in favour of the development of the centralized power grid over the remote, small-scale hydro technologies. Given that the centralized grid is confined to the Terai and generally serves the nation's urban population (7% of total), there is a strong urban bias in the pattern of development of the electrical power sector. Considering that there are only 27 SHP facilities among thousands of rural villages, it is unlikely that SHP resources will be developed at a rate that will serve more than a miniscule fraction of the rural population in the Hill Region.

The Objectives of Rural Electrification In Nepal:

Given that SHP projects are the only means of providing electricity to rural areas in the Hill Region, it is useful to consider the objectives of rural electrification policies. In the initial stages of planning rural electrification programs, the broad objectives of the policy were set out as follows (Nielson, 1979):

1) Rural electrification is to provide an infrastructure for rural industrial development. (cottage & craft industries) as a means for developing employment opportunities and cash economies in rural areas;

2) Electrification is to provide a substitute for traditional fuels, with the rationale of stemming deforestation and associated problems;

3) Electrification may also provide a replacement for imported fossil fuels (namely kerosene for lighting and diesel used for remote grainmills), as this would alleviate problems of foreign exchange associated with commercial energy imports;

4) Electrification may also generate ancillary social benefits, such as the improvement of education, health, communication, and transport services.

A more current list of rural electrification objectives (SHPD, 1986) includes the following additions which reflect both the basic needs of Nepal's rural population and the impetus to overcome some of the problems experienced with initial projects.

5) Electrification may be used to increase agricultural production through both lift-irrigation and small-scale fertilizer production;

6) Electrification projects should be planned to reducing foreign exchange and foreign expertise requirements of the program; To utilize, to the extent possible, indigenously manufactured equipment;

7) Electrification projects should involve the private sector in project construction and operation;

8) Electrification projects should utilize local labour in small hydro installations to reduce project costs and improve the cash economies of rural villages.

Most of the objectives of RE policy have been difficult to operationalize through the deployment of small-scale hydro technologies. More importantly, there is no apparent prioritization of these objectives. Given the emerging rural crisis of rapid population growth, deforestation and declining agricultural yields, it would follow that electrification would be best utilized if used as a subsitute for traditional fuels (2) and to increase agricultural production (5).

Potential and Actual End-Uses of Small Hydro Power:

The following is a list of possible end-uses of electrical power from SHP that has been set out by the SHPD. This set of potential end-uses generally reflect the objectives set out in the previous section:

1) Small-Scale Industries and Businesses
    - a) cottage /craft industries
    - b) sawmills
    - c) fertilizer plants
    - d) fish farming
    - e) dairy processing plants
    - f) agro-processing plants
    - g) tourist / recreation facilities
2) Lift-Irrigation Schemes
3) Residential Lighting
4) Public Services
    - a) health clinics
    - b) educational facillities
    - c) potable water systems
    - d) communication services (radio)
    - e) transportation (ropeways)
5) Electric Cookstoves

With regard to small-scale industries and businesses, very few of these end-uses of electrification have progressed beyond demonstration or pilot project stages. The exception is the use of grain mills/seed oil extraction machinery as a components of MHP units. Yet, these installations typically make use of mechanically driven systems and are rarely electrified. Although lift-irrigation pumps may be one of the most beneficial end-uses of electrical power, there are no known lift-irrigation projects that have been carried out in conjunction with SHP projects. Public services may have been marginally enhanced, though likely through the installation of lighting. However, electrification has not dramatically improved the operation of public services in remote areas.

Electrical lighting is the primary use of electrical power from SHP installations. While electrical lighting has been shown to displace kerosene consumption, members of electrified households have observed to stay up later burning their traditional wood fires later into night. In some instances, this has actually led to increased fuelwood consumption leading to the opposite result of fuelwood substitution. The tariff structure for household lighting is decidedly crude, as the costs of electrical metering devices are prohibitively expensive. Electricity charges are flat rate at $US .16 per 40w bulb per month. Not all village households can afford this tariff rate for lighting, and this tends to limit load factors on remote SHP installations. At this tariff rate, the costs of electrical cooking are prohibitive for nearly all households in Hill villages, and fuelwood is a far cheaper fuel despite it's increasing scarcity. In addition, the initial costs of an electric cookstove represent an exhorbitant cash expense to most village households. Even if the costs of electrical cooking were affordable, the electrical demand from cooking would quickly surpass the capacity of most of the currently operating SHP facilities.

It has been previously suggested that end-uses of electrification which diminish fuelwood consumption and increase agricultural production would be most appropriate in the context of the subsitience economy in the Hills. Yet, lift-irrigation systems have not been attempted (in conjunction with SHP projects), and electrical cooking appears to be too costly. Yet, there is some hope for finding alternative and appropriate end-use technologies. Low-wattage storage cookers (250 watts) have been developed and manufactured in Nepal, and four of these cookers could be installed for the more common 1 kW hotplate. The widespread use of storage cooking units would also even out the fluctuations in daily load cycles, thereby improving load factors on remote SHP electrification systems. However, the major problem with low wattage cookers is that they require a major reorientation of the cooking practices of village women. Yet, with the fuelwood savings from electric cooking, the cultural barriers to adopting the use of electric cooking may erode over time. Electric grain dryers are also being developed in Nepal, and these would diminish foodgrain storage losses (from rodents and fungus), which are known to be as high as 30% of net harvests. China has experimented with fertilizer generators which produce nitrous oxides by the electric arc discharge method. Apparently, a 3 kW unit can produce enough fertilizers for 5 - 10 hectares of agricultural land. If these figures hold in the field, this end-use technology may hold a tremendous potential for alleviating foodgrain deficit conditions in Nepal.

The Economic Performance of Existing Small Hydro Installations:

The SHPD has estimated benefit-cost ratios (B:C) based on composite capital cost estimates and the existing tariff structure for all existing installations. Table Three shows that these B:C ratios are generally poor as they are greater than a value of 1.0 (indicating a positive financial return) only when three conditions are met: 1) an interest rate of not more than 2%; 2) a load factor greater than or equal to 40%, and; 3) a plant capacity of not less than 300 kW. These conditions can be contrasted with actual figures of a 4% minimum interest rate on government development projects, 15 to 30% load factors, and average SHP plant capacities of 210 kW. In short, revenues from electricity tariffs generally only cover about half of operation, maintainence and depreciation costs for individual SHP projects. Essentially, this means that SHP projects are heavily subsidized by the Nepali Government and it appears that positive economic returns on SHP projects are not a priority of the SHPD.

Nonetheless, it is important to examine why SHP projects have demonstrated such poor economic returns. Generally, high capital costs prevent positive financial returns on Nepal's SHP projects. Table Four indicates that there is some economies of scale in power production across the range of plant capacities that fall into the small hydro class. However, these unit costs of Nepal's SHP projects are fairly extreme at any scale. SHP project costs in other Third World countries are generally much lower, sometimes a half to a third of the Nepali figures. A certain amount of this discrepancy can be explained by both the high transport costs of materials to the remote sites in the Hill Region, and by the high cost of design and engineering overheads. Yet, there are also likely to be instititutional factors which contribute to high project costs. There may also be conflicts of interest within the administrative body which oversees SHP Projects which leads to inflated project costs. Many members of the board of the SHPD also own engineering firms which receive many of the construction contracts for SHP projects.

Problems and Constraints to the Development of Small-Hydro Resources

The following lists provide a summary of the existing problems that inhibit the development of SHP resources in Nepal. These lists are broken down into three sections dealing with project planning, construction and operation. Many of these problems are interrelated and should be fairly self-evident to the reader. However, a brief discussion is offered for each of these categories in order to identify the more important barriers to the developement SHP in a Nepali context:

Table Three: Benefit:Cost Ratios for Existing Small Hydro Installations*

	Interest Rates:			
Plant Capacity:	0%	2%	4%	6%
100 Kw	.73	.60	.50	.42
200 Kw	.79	.65	.54	.46
300 Kw	1.00	.82	.68	.57
500 Kw	1.42	1.17	.97	.82
720 Kw	1.25	1.03	.86	.72
1000 Kw	1.25	1.03	.85	.72

* at a load factor of 40%

Source: Small Hydro Development Board, 1985

Table Four: Unit Costs of Small Hydro Installations by Plant Capacities

Plant Capacity Range:	No. of Installations:	Cost per Kw Capacity:
< 100 Kw	4	6599 $US
100 - 200 Kw	6	6076 $US
200 - 300 Kw	8	4826 $US
> 300 Kw	2	3857 $US
mean: 210 Kw	total: 20 of (27 projects)	mean: 4762 $US

Source: Small Hydro Development Board, 1985

1) Project Planning:

a) Productive and appropriate end-uses not planned as a part of projects
b) Economic criteria ignored / poor method of economic appraisal
c) Shortage of development funding (domestic and foreign)
d) Poor quality of site hydrological data / unknown streamflow parameters
e) Innappropriate choice of project scale, design or site.
f) High costs of engineering and design overhead

Many of the existing problems with SHP projects originate at the planning stage. Due to the unreliability of hydrological data, many projects are either over or under-designed. The siting of some projects have failed to account for extreme geological or hydrological events that are commonplace in the Himalayas. One painful example of this was in 1986 when a SHP facility in the Everest Region was completely obliterated by the bursting of an upstream glacial ice dam. Due to the physiographic and the hydrological characteristics of the Hill Region, a properly designed installation requires rather detailed studies of site conditions and advanced design techniques, thereby increasing engineering and design overhead costs. Yet, the most serious problem is that project costs continue to escalate at the planning stage beyond what are economically justifyable. Because economic criteria are largely ignored in the choice of design, siting and application of SHP projects, there is relatively little emphasis placed on an investigation of how project costs could be reduced, and which end-uses of power are most appropriate in the Hill environment. With regard to the shortage of development funding, this is a situation that could be turned around, given that only 2.3% of capital resources in the electrical power sector are slated for the development of SHP and MHP resources. However, increasing the funding for SHP and MHP projects is only justifyable if it can be demonstrated that SHP can generate favourable financial returns; an unlikely event, given the planning practices for SHP projects.

2) Project Construction:

a) High costs of imported electro-mechanical hardware
b) Poor site access / Difficulty of transport of construction supplies
c) Lack of communications with implementing agencies
d) Poor construction management
e) Long construction periods

Most of the problems encountered in the construction stage are a result of the remoteness of SHP sites. In short, the difficulty of transport and communications inhibits proper construction management and the timely completion of projects. These problems translate into greater project costs and the postponement of project operation. However, through simpified SHP technologies and the use of local labor and materials, there is much room for improvement in terms of construction procedures and reducing project costs. It is not unreasonable to assume that Nepali manufacturers of MHP hardwares can eventually expand their operations into the SHP scale.

3) Project Operation:

a) Low load factors
b) Poor choice of end-uses
c) Lack of spare parts for electro-mechanical hardwares
d) Tariff structures crude / not affordable
e) Limited technical manpower for operation & maintenance
f) Power pilferage

Problems with project operation are either those which limit the reliability of SHP plants and the economic returns on projects. The lack of trained personnel and spare parts translate into longer down-times and higher O & M costs in the long-run. As previously mentioned, electrical lighting is the primary use of SHP, though tariffs are generally above the average households ability to pay. This situation leads to low load factors and insufficient revenues. There are far more appropriate uses of electrical power, though productive end-uses of electrical power cannot be developed through the enterpreneurial efforts of village farmers without government financing. Clearly, if SHP projects are to become effective agents of development and are to produce favourable economic returns, productive end-uses of SHP need to be planned and implemented as a part of SHP projects. In particular, end-uses that both establish a base load on remote SHP systems and address the emerging problems of food and fuel resource scarcity, will be the most appropriate in the Hill village context.

A Village-Scale Simulation Model for Projecting Impacts of a SHP Project:

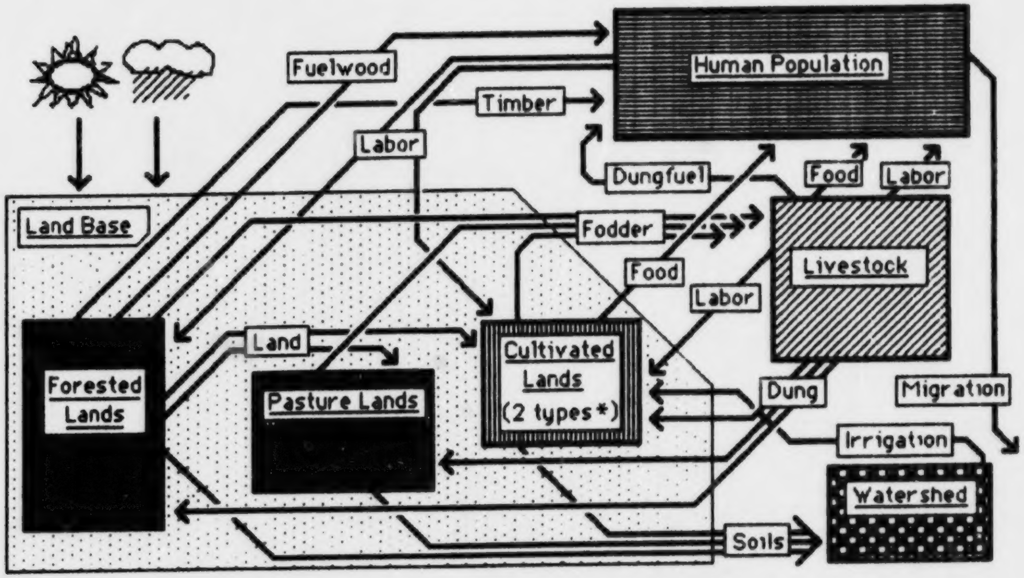
The above set of problems can be traced back to poor project planning, and they ultimately find expression in either increased project costs or in the incompatability of end-uses to rural conditions in the Hill Region. These findings call for an exploration of ways to improve the utility of SHP projects in a rural context, and a closer scrutiny of the economics of small hydro. There is also an urgent need for new methodologies for evaluating projects at the planning stage. The final section of this paper summarizes the author's methodology for a pre-project evaluation of project impacts and economic returns. This research stemmed out of the belief that economics of SHP could be improved by including productive end-use technologies that explicitly attempt to alleviate the problem conditions facing subsistence agriculture economies in the Hill Region. In short, a village-scale computer simulation model was devised to project the long-term impacts of a SHP project.

Figure Four shows a theoretical system of resource exchanges that are assumed to be common to subsistence agriculture economies of Hill villages. This system provides the conceptual basis for a stock-and-flow computer simulation model that was used to project the long-term (60-year) change in village resources both with and without a small hydro project. The computer model requires input information about the initial human and livestock populations, along with the areal coverage of cultivated, pasture and forested land within the village system. These initial parameters are set to reflect a conditions where population pressures are increasing, and forest resources are entirely depleted roughly halfway through the sixty-year term of the simulation. The model operates by assigning mathematical functions to each of the arrows represented in Figure Four, whereby populations, land stocks and resources are incrementally adjusted through sixty (annual) cycles. Throughout these cycles, the simulation model accounts for some of the major environmental feedbacks that can be expected within the village system. The more important environmental feedbacks include 1) increased rates soil erosion due to deforestation and agricultural land expansion; 2) The substitution of dung for fuelwood when forest resources are exhausted; and 3) the effects of population growth and village out-migration due to foodgrain and fuelwood deficits. While the simulation model is not the definitive model on rural Nepal, it does indicate what can be expected to happen in a Hill village faced with imminent food and fuel deficit conditions.

The next part of the analysis looks at the change the village system when it is altered by a SHP project. The impacts of the proposed 300 kW \SHP project include outputs of both a lift-irrigation system (300 m head) and a technology for fuelwood substitution (via 1 kW electric cookstoves) as a part of the installation. These end-use technologies were chosen because they were most likely to have the greatest positive impact on food and fuel resources within the village (low-wattage cookers and fertilizer production were not considered due to a lack of pertinent information). Figure Five shows a conceptual land-use profile of a Nepali Hill village with the proposed SHP Project. Once the parameters of both the SHP plant and end-use technologies were specified, a number of best-case assumptions were set out regarding 1) the technical outputs and reliability of the lift-irrigation and fuelwood substitution technologies; 2) the socio-cultural adaptibility to these technologies; and 3) their environmental impacts.

Figure Six presents the population, fuelwood and foodgrain projections of the village with and without the SHP project. In either the project or non-project case, the initial surge in village outmigration is caused by household fuel deficits. After fuelwood resources are exhausted, dung provides some of the household fuel demand, though this reduces the dung available for fertilizer.

Figure Four: A Theoretical System of Resource Exchanges in a Nepali Hill Village


Human Population
Fuelwood
Timber
Labor
Dungfuel
Food
Labor
Land Base
Fodder
Livestock
Food
Labor
Forested Lands
Land
Pasture Lands
Cultivated Lands (2 types*)
Dung
Migration
Irrigation
Watershed
Soils

* irrigated and unirrigated

Figure Five:

A Land-Use Profile of a Nepali Hill Village with a Small Hydro Project

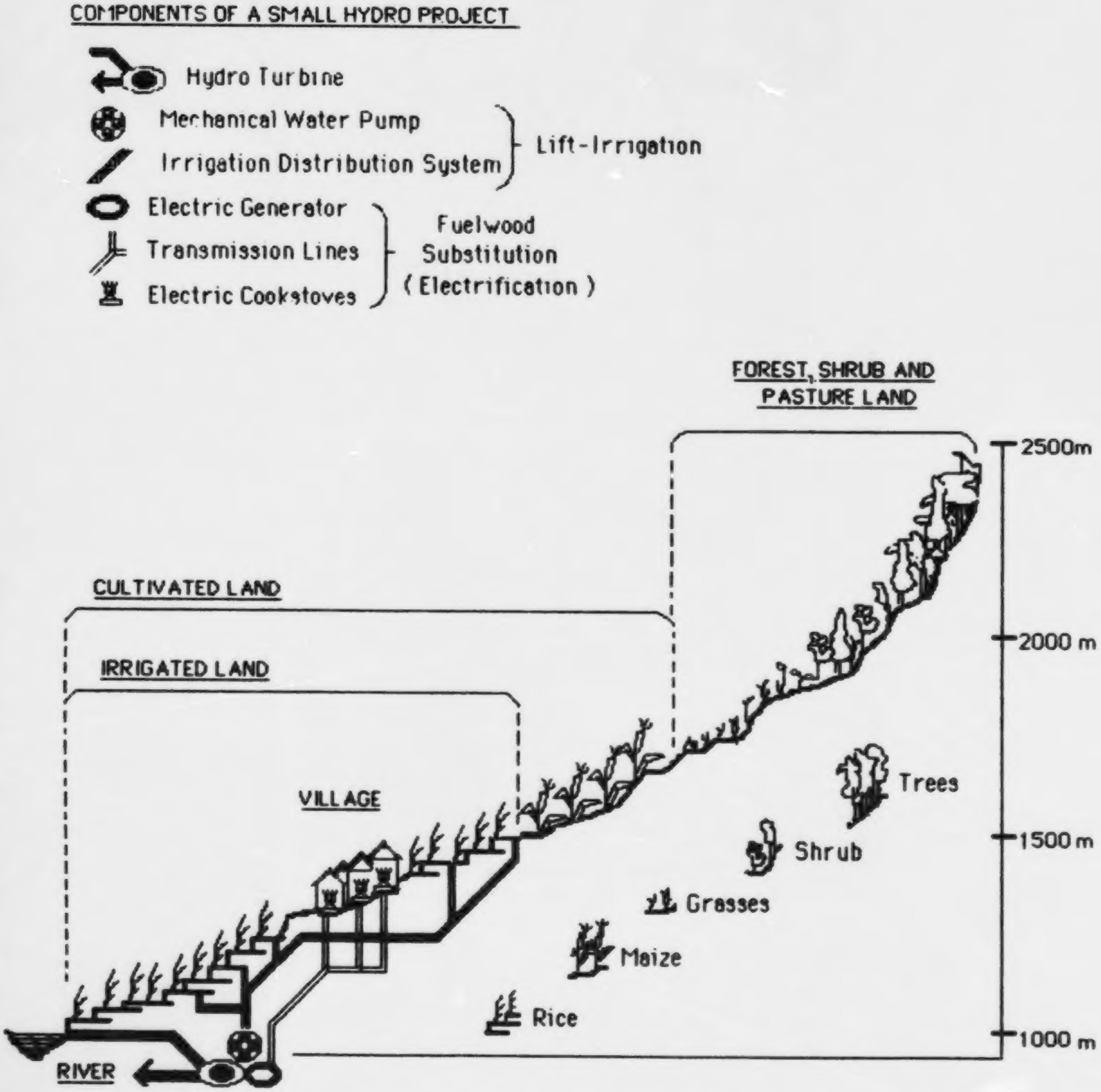
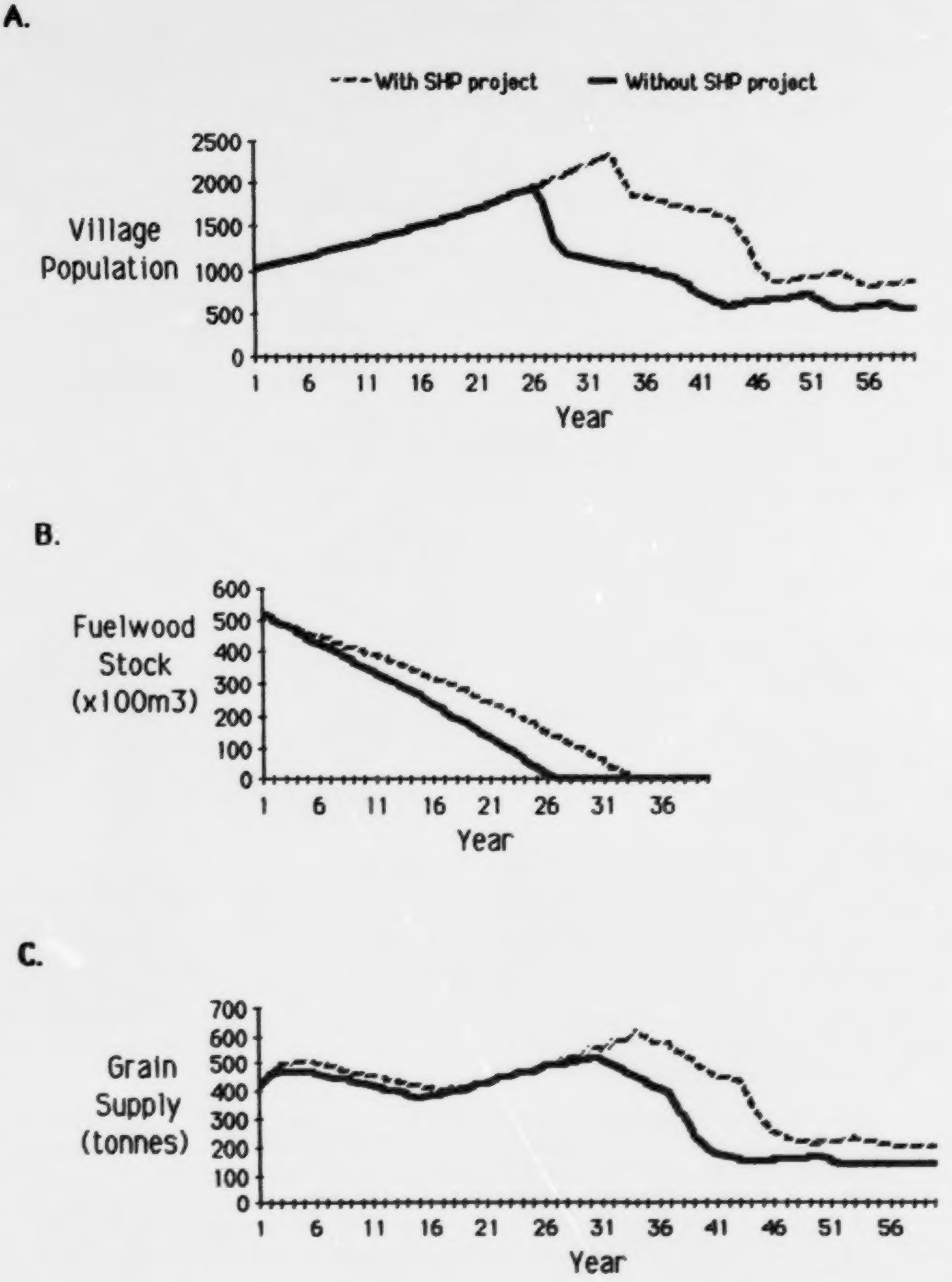

COMPONENTS OF A SMALL HYDRO PROJECT
Hydro Turbine
Mechanical Water Pump
Irrigation Distribution System
Lift-Irrigation
Electric Generator
Transmission Lines
Electric Cookstoves
Fuelwood Substitution (Electrification)
FOREST, SHRUB AND PASTURE LAND
CULTIVATED LAND
IRRIGATED LAND
VILLAGE
2500m
2000 m
1500 m
1000 m
Trees
Shrub
Grasses
Maize
Rice
RIVER

Figure Six: Sixty-Year Projections of Population, Fuelwood and Foodgrain Resources in a Simulated Nepali Hill Village

(with and without a Small Hydro Project)



Yet, it can be seen that the SHP project postpones both the exhaustion of fuelwood resources (graph B) and the dramatic drop in the village population (graph A) for approximately seven years. After fuelwood resources are exhausted, electric cookstoves service some of the household fuel demand, and more dung is available for fertilizing cultivated land. The grain supply graph (C) shows that the supply of foodgrains is also enhanced by the SHP project, though in years 17 through 26 (graph C), foodgrain production is virtually the same in the project and non-project case. Yet, in the final years of SHP project case, increased foodgrain production sustains a higher village population relative to the non-project case. Overall, the SHP project does not change the basic shape of the trajectories for the village population and fuelwood and foodgrain resources. However, the SHP project allows for an additional 21,0000 person-years (the area between the curves of graph A) to remain within the village over the 60-year period.

The economic assessment was performed using a standard Cost-Benefit Analysis. Capital costs of the SHP project were based on actual figures at US$ 4000/kW (see Table Four), for a 300 kW plant (including an electrical transmission system). The costs of the lift-irrigation system were assumed to be equivalent to the electrical transmission system. To these costs, the costs of cookstoves and terracing land were added. Total initial capital costs amounted to approximately US$ 1.6 million. Project life was assumed to be 30 years, with a plant rehabilitation costs incurred in year 31 (amounting to 50% of initial capital costs), thus extending project life by another 30 years. Project benefits were defined by pricing the difference in fuelwood and foodgrain stocks between the project and non-project cases. At the specified cost and benefit parameters, the proposed SHP project produces poorer financial returns than those reported by the SHPD (Table Three). At a discount rate of 0%, the project only produces a benefit:cost ratio of .30. A sensitivity analysis was also performed, though in summary, it confirms the basic finding that the economics of SHP are extremely sensitive to initial capital costs.

Conclusion:

The economic assessments performed by the SHPD and the author point to the obvious conclusion that the postive economic returns are prevented by the high capital cost of SHP projects. In contrast, micro hydro technologies have flourished in the Hill Region largely because project costs have been reduced by the indigenous manufacturing capability, and because their utility (as grainmills) is immediately apparent to village farmers. MHP projects are undertaken within the private sector and have been proved to be economically viable. Unfortunately, economic viability is not a feature of the government controlled SHP projects that have been used primarily for household lighting in district headquarters.

In general, current efforts should focus on improving economic returns through reducing project capital costs and finding economically viable end-uses of SHP. There is some hope that the costs of planning, constructing and operating SHP facilities may be reduced, given the removal of institutional barriers and further 'appropriate' adaptations of the technology to local conditions. Economic criteria must be adopted in the choice of sights, designs and end-uses of SHP projects. In order to justify investment in SHP and MHP technologies, the economic viability of projects must be established in both a pre-project and post-project appraisals. More specifically, the search for new end-use alternatives should focus on those that create a base load on the SHP system (thereby increasing load factors and improving the economic returns on projects).

However, the search for end-use alternatives should look beyond purely economic criteria. Disregarding economic viability, the current applications of both MHP and SHP projects are not likely to make any significant contributions toward the objectives of alleviating the problems of deforestation and declining agricultural yields. Unless the applications of small and micro-hydro are oriented more towards improving agricultural production and reducing fuelwood demand, they may do little to halt the gradual ecological collapse of the Hill region brought on by rapid population growth.

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SESSION 24:

CASE STUDIES - DEVELOPING COUNTRIES

Chairperson: D. Zoellner
National Rural Electrification Cooperative Association

HREP Nepal -
Low Cost Hydropower
with Maximum Local Training

By
M. Francis

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AHREP NEPAL - LOW COST HYDROPOWER WITH MAXIMUM LOCAL TRAINING

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Project Implementation and Objectives

Nepal is a country with vast resources of hydroelectric power which have so far not been exploited to any great extent. A number of large hydropower projects have been carried out successfully almost entirely by foreign contractors and organizations. A series of small hydropower projects have been less successful, due to low load factors, unrelability, high maintenance and operation costs. A major objective of the Andhi Khola Hydel and Rural Electrification Project (AHREP) is to show that it is possible to develop small hydro power at low cost and to build up the Nepali organizations capable of doing that.

AHREP is a project of United Mission to Nepal (UMN) financed by Norwegian Government Aid (NORAD) under agreement with His Majesty's Government of Nepal. UMN is an NGO made up of 37 christian missions who seek to serve the people of Nepal. In the area of hydropower they have sought to do this through the establishment of Nepali companies which will grow into institutions capable of functioning independently within a few years to give Nepal its own indigenous capability of developing hydropower resources. Three of these companies involved in the implementation of the project are:

> Butwal Power Company (BPC), the owner and designer of the power plant established in 1963 to build the Tinau Hydropower Project at Butwal Nepal.
> Himal Hydro & General construction Pvt. Ltd. established in 1978, the civil contractor specialising in tunnelling and hydropower development.
> Nepal Hydro & Electric (NHE) established in 1986, a company manufacturing electromechanical equipment for hydropower developments is responsible for that aspect of the project. NHE has a cooperation agreement with Kvaerner Brug A/S of Norway.

Each of these companies is owned jointly by UMN and HMG Nepal. UMN currently has the majority share and provides a number of key personnel. It is envisaged that UMN will within 15 - 20 years hand over its involvement in a way to be agreed with HMG Nepal. Training of local people and technology transfer are important emphases in these enterprises.

Construction of the project began in 1983 and is due to be finished in 1990. High speed of construction was not one of the objectives of the project. It was considered more important to use local resources and implement the project in such a way that could be replicated elsewhere in Nepal.

Project Description

The Andhi Khola hydro electric power plant (5 MW capacity) is situated at Galyang Bazaar, Syangja District in the middle hills of Nepal. Figure 1 shows the site layout. The Kali Gandaki River is only approximately 2 km from its tributary the Andhi Khola at the project site, but because of a long loop in the river course the power plant is able to exploit an elevation difference of 250 m. The plant is a run of the river plant with daily storage to be provided during the dry season by flashboards on top of a 5 m high dam. Water is taken off through a side intake with undersluice into a gravel trap then via an open canal to a sand trap. The 1.3 km long headrace tunnel takes water from there through the 300 m high ridge dividing the Andhi Khola Kali Gandaki valleys. The penstock runs in a vertical shaft which also provides access to the underground powerhouse, and the 1 km long tailrace tunnel discharges water from the power house into the Kali Gandaki.

Construction of the power plant has been linked with a number of different programmes. The area has no electrical power at present, and rural electrification is an important aspect of the project. Forestry, promotion of rural industries, and drinking water programmes have also been included in the activities of UMN asociated with AHREP. Water from the headrace tunnel will also provide irrigation of upto 300 ha agricultural land in the Kali Gandaki valley.

Aspects of Layout

Major factors in deciding the project layout were a suitable intake site and considerations of access and slope stabilty.

The intake site was chosen as a river section with evident rocky bed and a terrace 100 m downstream suitable for the desilting arrangement.

With 2.3 km of horizontal tunnels, a 250 m vertical shaft and a 35 m long underground powerhouse a very large proportion of civil works for the project is underground. At the feasibility design stage a variety of layouts were studied including a surface penstock and powerhouse but a decision was made to site most works underground because of the very unstable slopes in the Kali Gandaki valley. A feature of the valley is old river terraces comprising recent sediments between 150 m and 200 m above the river. These are deeply incised by small streams and there is plenty of evidence of undercut slopes and slumping.

Access to the powerhouse is via the 250 m deep vertical shaft. This solution was chosen because of the particular difficulties which would be involved in constructing an access road on the unstable slopes of the Kali Gandaki valley. The shaft site is reached from the main Pokhara to Butwal highway by a 1 km long road constructed at the begining of the project. Two ropeways have been constructed to supply the tailrace portal with materials. One from the shaft site for cement and equipment and another crossing the Kali Gandaki for sand and aggregate. Compressed air is supplied to the tailrace by an over-land pipe fed by compressor at the shaft site.

The cost of an access road to the tailrace portal would have been a very high proportion of the project cost. The layout chosen making use of ropeways resulted in substantial cost savings over a conventionally planned project, and minimal enviornmental impact.

Intake Design

The hydrology of Himalayan rivers poses many problems for hydropower development. The long dry season with little rain followed by monsoon from the end of June until September means that there are relatively high flood levels and low base flows. The Andhi Khola is gauged 8 km downstream of the site, but there were only 11 years of records available. The 1:20 year flood is 1460 m^3/s and a 1:5 year 7 day low flow is 1.6 m^3/s. Due to the heavy rain intensity there is a high silt load during the monsoon; it has been measured as high as 2250 mg/l.

The diversion of water is achieved at a 5 m high 60 m wide concrete gravity dam founded on rock, and the sand trap 100 m downstream is situated on a rocky terrace above the river channel providing adequate head for flushing of sediments. A sluiceway with 2 x 2.5 m radial gate which will be opened during the monsoon period to scour the area in front of the side intake, is provided at the left abutment of the dam. During the monsoon continuous flushing of gravel and sand traps will be practised. The sand trap has a prismoidal section designed to settle all particles larger than 0.3 mm and a flushing channel running the length of the basin. The capacity of the intake is 4 m^3/s.

The design of an intake works which would function perfectly under every condition on a river such as the Andhi Khola would be extremely costly. In the design of AHREP some economies have been made on the basis that it is satisfactory to close down the power plant under unusual conditions which may occur 1:10 years. A distinction has to be made between situations which threaten the integrity of structures and those which may cause some interruption to power production. For example, occasional manual removal of silt from the intake canal is certainly less costly than extra capital costs of higher protection works and gates to prevent inundation of the structure during highest flood conditions.

The design of the intake works was made with careful consideration of local prices. Labour rates in the area are relatively cheap by comparison with international costs. ($1 a day is a typical daily wage for unskilled labour) Stone rubble masonry retaining walls were found to be more cost effective than reinforced concrete on the intake canal. Some savings were made by the use of rock bolts to anchor the walls into rock. The concrete gravity dam was designed to be M15 concrete with 40% plums (rocks of size 200-300 mm dia) and a 400 mm surface layer of higher grade M25 concrete to prevent abrasion. The quantity of relatively expensive cement was minimized by measures such as this.

The high levels of monsoon flow prohibited any work on the intake between June and October in the early phases of construction. Diversion of the river has been achieved by means of low rock fill cofferdams sealed with clay.

Tunnels

The bedrock of the project site is a highly fractured and folded phyllite with occasioned quartzite intrusions and clay seams. Excavation is done by drill and blast and all underground openings require lining very soon after blasting. The headrace and tailrace tunnels are minimum size tunnels. Lining with 350 mm thick stone rubble masonry supported by precast concrete arch plates as permanent formwork, is carried out on a daily basis right upto the face.

At an early stage during construction of the tailrace concern was felt about cracks in the lining and movement for some months after completion. A variety of lining techniques were tried out. Shotcrete was a new technique for Himal Hydro which proved to be reasonably successful after extensive trials, but more expensive than the rubble masonry. Problems were experienced in the time for erection of reinforcement where the stand up time of rock was short, and the high percentage of rebound using a dry shotcrete machine. An expensive reinforced concrete lining was used in one section but using this progress was slow due to time taken for erection of formwork and reinforcement. Expert advice confirmed that the rubble masonry was as good as any lining for this type of rock. Backfilling of overbreak with dry stones allows for some adjustment of the rock mass. The concrete floor is laid a minimum of 10 m behind the face again to permit some movement in the rock. Monitoring of movements has shown that a stability is reached after 3 - 4 months, although there have been some repeated movements probably associated with change in groundwater levels during the monsoon.

Removal of spoil from the tunnels is by manually loaded and propelled rail cars in the tailrace and by wheelbarrows in the headrace. The mucking capacity is not large and is one of the main limiting factors in controlling the daily advance of the face, together with time for construction of lining. The average weekly advance is around 6 m, not fast in comparison with many international contracts. Himal Hydro has however developed a suitable daily excavation and lining cycle for tunnelling through difficult rock conditions using appropriate technology at very low cost. The cost of these lined minimum size tunnels is approximately $430 per metre.

Shaft and Powerhouse

The 250 m deep 4 m diameter vertical shaft is designed to hold the penstock and to provide access to the power house. Excavation of the shaft has proceeded down by drill and blast, the spoil being removed in skips by a crane which will serve for equipment and personnel transport when the project is complete. Shotcrete with steel reinforcing mesh is applied immediately following excavation.

This is the first vertical shaft excavated by Himal Hydro and progress has been slower than might have been liked. Reliability of mechanical equipment has been one problem. Maintenance is not straight forward in a situation where parts supplied from abroad take at least 1 month to obtain. The necessity of having plentiful back up has been appreciated.

The 6 m wide and 35 m long powerhouse has been laid out to minimise the width in view of the poor rock quality. Switchgear will be located in small rooms below the floor level between the 3 units saving excavation and concrete. Height of the powerhouse is determined by clearance between crane beam and units for the generator stator, the largest piece. By using an appropriately designed lifting yoke this is minimised.

Excavation of the powerhouse started in May 1988, a new type of challenge for civil contractor, Himal Hydro. Some apprehension has been felt about opening a cavern of this width in such highly fractured phyllite. Improvement of shotcrete technique and quality is felt to be crucial for suceessful lining of the powerhouse. So far only dry-mix shotcrete has been used here but a wet-mix shotcrete machine purchased second hand in Norway will enable production of a more reliable quality of shotcrete with steel fibre reinforcement and microsilica additive. This should provide the immediate strong support required by this rock, and will be the first wet-mix shotcrete used in Nepal.

Electromechanical Equipment

Almost all of the electromechanical equipment has been obtained form Norway at virtually no cost apart from packing and shipping. The three 1700 kw Pelton wheel turbine sets were installed in the Mesna powerstation in 1926 and removed when it was made redundant. The crane at the shaft head had been ordered for a ship building yard, but never put to use there. It has been modified in Nepal to meet project requirements.

The project is a good example of where equipment considered out of date in a European country is put to good use in a developing country. In many respects equipment manufactured 60 years ago in Europe is easier to maintain than the most sophisticated machinery in a country like Nepal. The facility to maintain the equipment is an essential prerequisite for this type of strategy to be successful. NHE the manufacturer of hydropower equipment has been established with the capability to do this. They will recondition the 3 turbine sets and be responsible for installation of all electromechanical equipment.

Materials and Workforce

One of the biggest problems of construction in rural areas of Nepal is the difficulty of obtaining supplies. AHREP has the advantage over many small hydro sites that it is on the road but there is no telephone link with the outside world. Letters are sent by a mail runner to Butwal and Kathmandu three times a week, however even in Kathmandu, machinery spare parts are not readily available with the formality of import licences and cost of airfreight making delivery periods for urgently required imported goods unacceptable.

It has become a policy to purchase most construction equipment from Asian countries where possible as parts can more easily obtained. Many items have also been made or adapted at the NHE workshops in Butwal, and the site has a small workshop too.

Cement is one material which has given persistent problems. Careful programming of construction and stock control is essential where the monsoon period with high humidity is so difficult for cement storage. Local supplies of sand with high mica content and fine grading have also made production of good quality concrete difficult.

The policy of using a local workforce has inevitably given some limitations in speed of construction. Nepali technical and administrative staff have often been brought in from outside the area, but most labourers and skilled workers have been recruited and trained locally . Many local people are skilled in the traditional crafts like building stone houses but few have previous experience of working in tunnels for example. These people have shown ability in learning the new skills required but there has always been a limited pool of people available which is reduced at the time of year when agricultural activity is highest.

Transmission and Rural Electrification

The project will be connected to the national grid by a 33 kv 20 km long transmission line towards Tansen to the south. The construction of this line completed in June 1988 has a number of interesting features. Long spans of upto 800 m are used crossing the deep gulleys wherever possible to minimise the number of towers. NHE have developed two standard types of tower, lattice and tubular types. Both can be transported by porters in sections over the hilly terrain and can be easily assembled.

Rural electrification has many challenges in a mountainous country like Nepal. The distribution network to small villages requires careful planning. A survey was carried out in December 1987 to discover the potential for economic growth resulting from rural electrification. This will form the basis for the planning of distribution lines and a tarrif policy.

It is hoped that electricity will be extensively used for lift irrigation and cooking, the latter in order to reduce demand for fire wood and halt the rapid deforestation. Education will be a key part of the rural electrification programme, but the difficulty of getting people to change their food preparation habits is not underestimated. Work has been done to develop a low wattage storage cooker which may be issued at a subsidized price with electricity connection. Together with a tarrif policy based on controlling peak consumption rather than kw hrs it is felt that this is the only way of getting people to change from wood to electricity.

The pilot electrification project starting in 1988 when the area is connected to the grid will provide an opportunity to try out inexpensive technology for rural distribution, untraditional tariffs and various forms of users participation before the AHREP plant starts generating in early 1990.

Project Cost

The currently estimated capital cost of the project is as shown in Table 1.

Table 1 AHREP CAPITAL COST

Item	Cost US$
Headworks	420,000
Headrace Tunnel	551,000
Shaft superstructure and Surgetank	119,000
Shaft and Penstock	427,000
Powerhouse Civil	306,000
Powerhouse Plant *	982,000
Tailrace tunnel	468,000
Support Facilities	282,000
Contingencies	355,000
Total Cost Hydropower plant	3,910,000
Transmission Line	307,000
Rural Electrification	1,041,000
Total Project Cost	5,258,000

* valued at current prices.

The cost per kw installed is comparable with, and lower than many large hydropower projects developed in Nepal. Compared with other small hydro projects the cost is much lower, although factors of distance from motor road must be taken into account. Table 2 shows comparitive costs of different projects.

The low cost has been made possible by use of appropriate technology with labour intensive construction.

Table 2 COMPARATIVE COSTS OF HYDROPOWER PROJECTS IN NEPAL

Project	Completion Date	Capacity kw	Capital Cost US$ M	Capital cost US$/kw installed
AHREP	1990	5,000	3.90	782
Kulekhani I	1982	60,000	54.40	909
Kulekhani II	1986	35,000	38.60	1,104
Marsyangdi	1990	69,000	200.00	2,899
Dhading	1980	32	0.09	2,906
Phidim	1981	240	0.30	1,229
Doti	1981	200	0.67	3,365
Syangja	1982	80	0.28	3,500
Jomson	1983	240	0.66	2,738
Jumla	1983	200	0.76	3,780
Gorkha	1983	64	0.11	1,646
Helambu	1985	50	0.24	4,840
Darchula	1986	50	0.38	7,520
Tatopani	1990	1,000	1.80	1,800

Appraisal of achievements

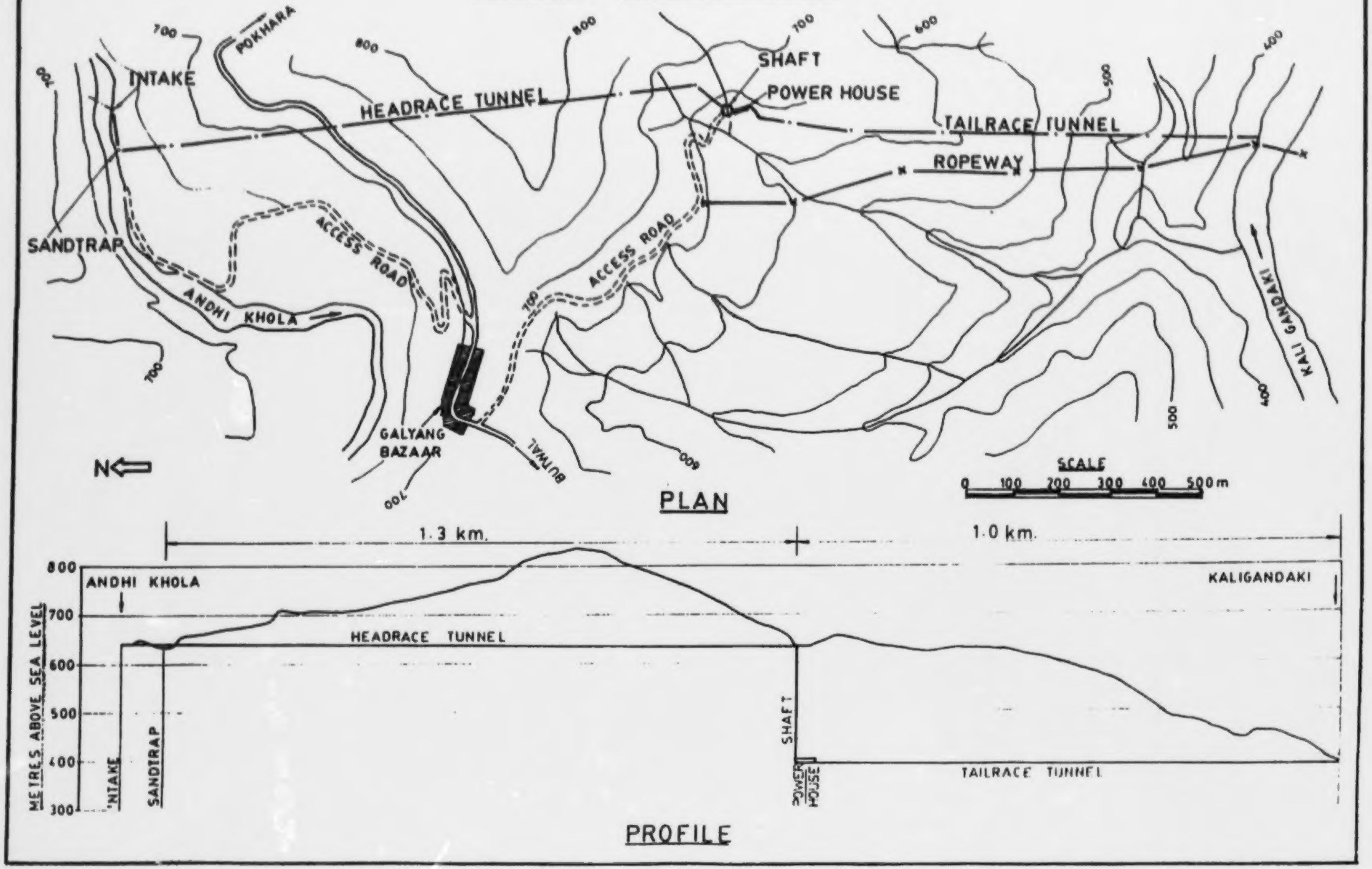
Appraisal of the project is perhaps premature with the hydropower plant yet to be completed. However there are considerable effects which can be already seen.

Himal Hydro who started the Project with limited tunnelling experience, now have expanded to take on other contracts in addition to AHREP. The project has provided for them a stable base load of work and training opportunity for personnel. In 1982 they employed no Nepali civil engineers and only 2 civil overseers. Today they employ 5 civil engineers 10 overseers and around 500 other Nepali staff. This expansion has been made possible by AHREP and lays the foundation for less dependance on expatriate personnel. NHE has so far had less success in getting contracts for work outside AHREP, however, the work done in establishing a galvanising plant and production of innovative designs of transmission towers is valuable.

Experience to date indicates that the project cost will not exceed the current estimate. AHREP will be one of the cheapest sources of power in Nepal. This has been made possible by innovative use of appropriate technology. Ropeways, low cost tunnel linings, introduction of shotcrete, use of local labour and resources are some of the key factors in this.

AHREP demonstrates a model for small hydropower development where an emphasis has been on maximising local benefits during construction. There is much evidence of this in increased cash incomes and improved rural infrastructure occuring at a rate which can be taken by the rural community.

FIGURE 1 PROJECT LAYOUT


PLAN

PROFILE

INTAKE
SANDTRAP
POKHARA
HEADRACE TUNNEL
ACCESS ROAD
ANDHI KHOLA
GALYANG BAZAAR
BUTWAL
SHAFT
POWER HOUSE
TAILRACE TUNNEL
ROPEWAY
KALI GANDAKI
N
700
800
600
500
400
SCALE
0 100 200 300 400 500m
1.3 km.
1.0 km.
METRES ABOVE SEA LEVEL
800
700
600
500
400
300
ANDHI KHOLA
KALIGANDAKI
HEADRACE TUNNEL
'NTAKE
SANDTRAP
SHAFT
POWER HOUSE
TAILRACE TUNNEL

Micro-Hydro in Developing Countries: Cost-Effective Power and Local Participation

By
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MICRO HYDRO IN DEVELOPING COUNTRIES: COST EFFECTIVE POWER AND LOCAL PARTICIPATION

Godfrey Cromwell, Ray Holland, Andy Brown, Greg Wishart.
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MICRO HYDRO IN DEVELOPING COUNTRIES: COST EFFECTIVE POWER AND LOCAL PARTICIPATION

PART 1 INTRODUCTION

Experience in a number of countries, of which three (Nepal, Sri Lanka, Peru) are discussed here, has highlighted five essential elements of successful micro-hydro schemes. Such schemes are:

i) Demand-led
ii) Low cost
iii) Integrated into existing systems of water management

and involve:

i) Local institutions and manufacturers
ii) Comprehensive training

These elements are discussed in more detail below.

I DEMAND

Levels of demand and end-use technologies must be considered from the outset. Most successful projects have been undertaken in collaboration with local communities [12] and rural development organisations able to identify local power needs in terms of both improvements/replacements for existing end-uses and/or the introduction of new ones.

Expressed demand is frequently for domestic power - particularly lighting - but this by itself seldom provides an adequate load to justify the installation of a micro-hydro plant [17], [29]. Thus, while it is important to recognise this felt need, [22] it is via more direct raising of the productivity of local labour (and hence effective demand) that ability to pay for the installation will be determined. [19]. Under such circumstances promotion of end-uses is a priority for project financial feasibility and domestic power is only one of a number of options for generating revenue.

End uses commonly associated with micro-hydro are:

Agro-Processing

Grain Milling
Rice Hulling
Oil Seed Pressing
Coffee Hulling
Rubber Processing
Tea Processing
Vegetable Chilling
Sugar Cane Crushing
Crop Drying

Other

Saw Mills
Power Looms
Carpentry Workshops
Wool Yarn Preparation
Mechanical Workshops
Domestic Power

End uses are generally in agro-processing or agro-related industries while domestic demand tends to build up slowly (typically at less than 20% per annum) [1].

II LOW COST

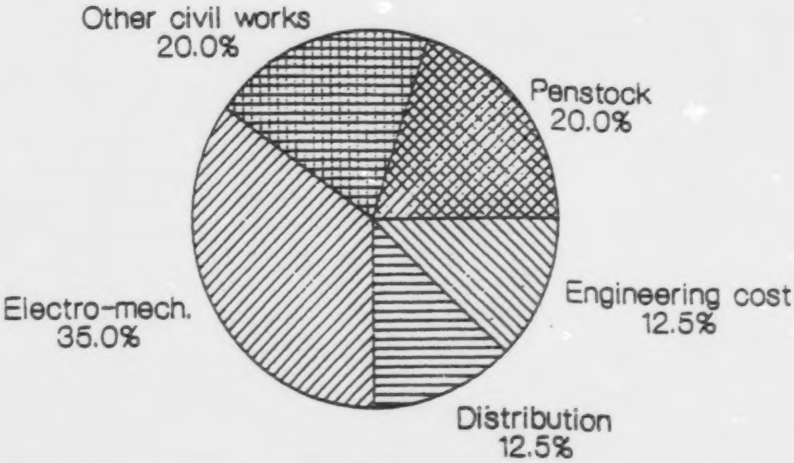
(a) General

Potential or actual demand is generally not sufficiently concentrated in remote rural areas of developing countries to justify large scale installations. Thus micro-hydro is often the least-cost means of providing power in decentralised plants where load factors exceed 20%. Furthermore, micro-hydro can compete on cost terms with large hydro schemes (see Appendix 1).

Optimisation of equipment quality within cost constraints is particularly necessary in areas where capital may be at a premium - particularly if it is foreign exchange capital. Individual contributions to total capital costs typically occupy the proportions shown in Figure 1.

Figure 1. Typical Capital Cost Proportions for Micro-Hydro Installations

Figure 1.



CAPITAL COSTS
Typical micro-hydro projects

Total installation costs in the remote rural communities where ITDG works should amount to no more than US$2,000/kW of which the turbine generator and controller constitute no more than US$700. These levels have been achieved for plants with acceptable performance requiring simple but regular maintenance and with a minimum expected life of 20 years. Country examples include Argentina, Bolivia, China, Colombia, Nepal, Pakistan, Peru, Sri Lanka and Thailand [4, 27, 14, 19, 15, 20, 6, 17, 21].

(b) Technology

i) Turbines

While turbines may initially be imported, the aim in countries which have adequate demand [11] for micro-hydro equipment may be to produce machines locally making use of proven designs. In such cases, therefore, the building up of local manufacturing capability at an early stage is critical. In addition, the current level of local manufacturing capability will affect choice of turbine type, at least in early stages of micro-hydro programmes.

For plants of up to 100 kW capacity - ITDG's principal area of experience - the following turbine types are recommended:

Propeller turbines with fixed or variable guide vanes for low head

Crossflow or Turgo wheel turbines for medium head installations

Multi-jet Pelton turbines for medium-to-high head installations

The use of belt drive to the alternator allows considerable extension of turbine working head and power range. This in turn facilitates standardisation of turbine types for manufacturers catering to a national market.

Electronic load control (see below) makes possible the use of simple fixed geometry turbine designs.

ii) Civil Works

Low concrete weirs or where appropriate, temporary brush and boulder weirs keep in-stream construction to a minimum.

Great account should be taken of local traditional water management techniques. For example, the potential for use of existing irrigation weir technology rather than scaled down small-hydro intake structures.

The use of carefully upgraded traditional techniques has proved very successful in keeping total civil costs, excluding penstocks, down to between $200 and $500/kW.

UPVC penstocks have proved cheap and reliable, although local acceptance is often difficult at first. Where locally rolled steel penstocks are designed around standard sheet sizes welding and wastage costs are minimised.

iii) Control and Governing

Appropriate selection of control and governing technology can range from ungoverned systems (Nepali mills) to more sophisticated methods such as Electronic Load Controllers (ELCs) and microprocessor-controlled electrical actuators.

For plants up to 200 kW the experience of ITDG and others has shown that Electronic Load Controllers (ELCs) (which feed excess power to a ballast load to maintain constant turbine speed) are the cheapest effective means of control.

Further advantages of load control governors are:

1. Reliability. (No moving parts)
2. Speed of response.
3. Flywheel is not required.
4. Minimises surge pressures.
5. Ability to operate with simple turbine designs without complex valves, or guide vanes.
6. Improved motor starting ability.
7. Ease of local assembly, installations and maintenance.

Simple electronic load management systems have proved effective in improving energy usage (eg ITDG Sri Lanka).

iv) Generators

Micro-hydro projects normally make use of mass-produced and readily available synchronous alternators. However, alternators remain the weakest link in most systems and require careful specification for micro-hydro use. Recent development and use of induction motor generator systems has reduced the generator costs of installations with less than 30kW capacity - for example in Nepal. Industrial motors used as generators are robust and the cheapest solution below 30kW. They are popular in village lighting sets, and recent developments on control systems are allowing their use with small industrial loads.

III EXISTING WATER MANAGEMENT

Hydrological studies should consider micro-hydro installations in the context of the total hydrological system - both natural and man-made and failure to do so can lead to project failure [9]. The involvement of existing local organisations such as channel committees is essential when considering issues of plant management and end-use control. The priorities of the user community - which may conflict with the use of water for power generation - will determine the success of micro-hydro installations. Integration of the demands of micro-hydro plants into existing systems assists their reconciliation with potentially conflicting water demands such as irrigation

Without local participation in the identification and resolution of such potential conflicts, plant viability will be left to chance. In addition the inclusion of local water management techniques can reduce installation costs (see Civil Works above).

IV LOCAL INSTITUTIONS AND MANUFACTURERS

During the initial stages of micro-hydro adoption it may be necessary for outside agencies to assist in project funding, particularly at the pilot/demonstration stage [2]. Subsequently, however, local financial institutions should be encouraged to take over the role of micro-hydro financing. In contrast to autonomous but transient foreign agency presence such institutions tend to have a deeper knowledge of the local circumstances relating to each project. This is especially true of those financial institutions which have extension departments or which operate project/site appraisal services - for example the Agricultural Development Bank of Nepal (see below).

In addition the use (or training) of local capability in financial institutions for economic appraisal, and in consultants and rural development organisations for site surveys, incurs low costs relative to the use of expatriate project designers. The evolution of local capability in these areas both improves post-installation management and benefits other projects undertaken.

Benefits of cost-minimisation and sustainability from local design, manufacture and installation of micro-hydro are discussed above. Management and maintenance of installations and their end-use technologies can also be largely carried out by appropriately trained local operators. For more complex routine and corrective maintenance a regional team with multi-disciplinary training (including knowledge of end-use equipment) is the most cost-effective, flexible and timely solution.

V TRAINING

Successful technology transfer includes development of local capacity to identify, design and implement projects. This allows not only the fullest local participation in the project cycle but also cost savings via the use of local skills and equipment. In developing countries this may involve the training of:

(a) Local institutions in project identification, planning and implementation;

(b) Local manufacturers in surveying, design, production and installation of both micro-hydro and end-use equipment;

(c) Users in the operation, maintenance and management of micro-hydro plant and end-uses.

Conventional survey techniques can be very costly when applied to small and remote sites. Careful training and appropriate equipment have allowed feasibility studies to be prepared for between $30 and $300 in Sri Lanka and Nepal.

Simplified hydrological methods, based on graphically presented data have proved accurate for parts of Sri Lanka and are being developed for key areas in other countries [13]. Salt dilution gauging replaces the current meter method for cheap and accurate spot readings. Pressure gauges and microbore tubing replace conventional levelling equipment [3].

Access to engineers is difficult and expensive in the rural areas of developing countries. Multidisciplinary training of a local operator reduces the need for external professional assistance, particularly on very small systems.

PART 2 CASE STUDIES

(a) NEPAL

In Nepal, despite chronic scarcity of productive land, 90% of the population depend on agricultural production and 95% of household energy requirements are met from traditional sources (fuelwood and waste products). No fossil fuels have been discovered in Nepal and the balance of energy requirements is imported within the constraints of the international oil markets and escalating shortages of foreign exchange. Average incomes in Nepal are among the lowest in the world.

However, Nepal has high potential for widespread hydro power generation as well as a long history of hydro power application [25]. While total output from small hydro is only 8.33 MW, it is the socio-economic and infrastructural contribution of this power provision to the development of rural areas that are most important.

Micro-hydro is now successfully established as an indigenous technology. What are the elements which made it successful? What still needs to be done?

Project Identification

Prior to the introduction of micro-hydro turbines, hydropower was harnessed using traditional water mills (ghattas). Although only capable of flour-milling (as opposed, for example, to rice husking or oil expelling), traditional mills were based on the use of local raw materials, technical ability, desired end-use and methods of payment (a proportion of the end product as payment in kind). As external contact increased the demand for simple prime movers to drive agro-processing machinery and replace tedious, exhausting, manual methods of processing was partially met by the introduction of diesel-powered mills.

While demonstrating the demand for equipment capable of driving agro-processing machinery, such diesel mills are only viable in areas with access to fuel and have run into serious problems of recurrent fuel and maintenance costs. Furthermore, the repair of diesel machinery requires complex skills often not available in rural areas.

By contrast, micro-hydro has low recurrent cost requirements, is simple to maintain and is not tied to areas with access to fossil fuels. As such it provides a viable alternative to diesel-powered machinery and can be extended to the more remote areas.

In response to rural demands for motive power two aid-funded workshops experimented with cross-flow and Pelton turbines and undertook pilot micro-hydro projects. Feedback from these projects led to improved blade strength and improved drive belt arrangements. A standard design was developed in the mid-1970s using cross-flow turbines. Pelton turbines were rejected at that time since associated problems of land and water rights made them incompatible with existing tenure systems.

MPPU's (Multi Purpose Power Units) capable of driving agro-processing machinery were also developed locally during the 1970s as low-cost replacements for ghattas. They continue to find a strong market.

Early MPPU and micro-hydro systems were only able to produce mechanical power. However, over the last 8 years, many have been electrified and around 80 all-electric schemes have been commissioned.

Severe fuelwood problems have led to the development of locally-made high-efficiency, low wattage cookers, which can also store 'off peak' energy as heat.

The introduction of positive temperature co-efficient diodes (PTCs or 'everlasting fuses') has been a major advance. This system replaces expensive meters and limits to a fixed amount (say 200 watts) the current available to each consumer. As a result high load factors are encouraged, tariff setting and collection is simplified and system overloads - common in remote systems - are prevented. Power is sold on the basis of installed watts - as was the case in many early Scandanavian systems.

With rapid growth of local demand, the number of installations has increased. More than 100 cross-flow and MPPU systems were installed in 1987 [23].

Localisation

The emphasis on training at the workshops mentioned above has allowed a number of ex-employees to become turbine-producing small manufacturers. In addition, Nepali micro-hydro organisations are now installing megawatt systems. The two workshops mentioned above have been localised and the design, manufacture, installation and management of micro-hydro projects are carried out entirely by Nepalis. Despite a generally weak industrial base, some ten Nepali manufacturers now include turbines in their range of products.

As is appropriate with a locally designed and developed technology, ITDG's emphasis has been on training in areas less familiar to local organisations. Specifically ITDG has focused on the electrical aspects of micro-hydro (control, generators, end uses), as well as hydrological survey techniques and economic analysis. Finance has been obtained or provided for local research and development of electronic equipment and for courses for designers and technicians.

Project financing has also been localised via the Agricultural Development Bank of Nepal (ADBN) and this has been a major factor in the dissemination of micro-hydro in Nepal since 1974. Over 80% of micro-hydro installations have been ADBN funded at commercial rates and the bank has also been involved in the promotion and dissemination of micro-hydro technology. The activities of 362 ADBN field offices and two Appropriate Technology Units include technical and economic feasibility studies and monitoring of the number of installations in different areas. In addition, the award of ADBN contracts to local manufactuers has assisted in the promotion of an infant industry.

Cost-effective equipment, based on the use of local skills and components, means that typical plant costs amount to US $1,000/kW (See Figure 2 below). On the basis of ADBN appraisal, credit is extended to schemes that show potential to be self-supporting and capable of servicing loans. Appraisal is based on the identification of adequate local demand for productive end-use technologies, available management ability and any potential competition from other installations (diesel or micro-hydro). This is in contrast to government small-hydro schemes which - with 15-20% load factor in the initial stages, high staffing levels, low tariffs and high system losses - require continuing subsidy. Government schemes may be justified on a least-cost basis relative to diesel and grid alternatives, but the private and community schemes funded by the ADBN (and discussed here) require a positive internal rate of return on capital invested.

In such schemes ownership has been mainly by rural entrepreneurs with sufficient capital to invest and with access to outside contacts (eg for marketing of mill products). The increase of local processing capability, the improved quality of product obtainable using micro-hydro ago-processing equipment and the reduction of the drudgery, especially for women, of crop processing have also brought definite benefits to local society. In addition any multiplier effects from the income generated, employment created and technical knowledge gained are also likely to be beneficial. Finally, the availability of domestic electric power fulfills a percieved need of local communities and may reduce pressures for rural-urban migration.

Figure 2 Typical Capital Costs of Micro-Hydro Installations: Nepal

Schemes	Total $ Cost	Cost/kW	Op Cost	Ann Rev	Payback (yrs)	IRR (%)
Turture	8,300	1,040	993	3,953	2.8	35.7
Turture (Elec)	4,236	536	414	1,306	4.8	20.5
Manbhak	7,784	1,038	1,123	2,026	8.6	9.9
Ambut	9,923	1,103	2,492	4,296	5.5	17.6

Notes:

1) These three schemes are mechanical drive mills and income is from agro-processing

2) Tuture was later electrified by adding a 10kVA synchronous alternator. Figures shown are for the add-on costs of alternator, drive, transmission lines etc.

3) 20 year plant life is assumed

4) All figures are US$. US$1 = 13.244 (1982) [26].

Computed from: East Consult (P) Ltd (1982) [7].

East Consult (P) Ltd (1984) [8].

Conclusion

The demand for energy in rural areas of Nepal was until this century, met by water or hand-driven technologies'. With the advent of MPPUs, diesel and micro-hydro installations, demand declined for such laborious and relatively inefficient traditional methods where modern alternatives were available and affordable. In addition the electricity generating capability of diesel generators and micro-hydro plants are attractive to rural communities seeking access to facilities such as electric light.

In cost terms micro-hydro plant is cheaper per kilowatt than equivalent diesel machinery (see Figure 3) and incurs far lower recurrent costs. In Nepal, credit is available to enable high capital costs (relative to those of diesel equipment) to be affordable by rural entrepreneurs or communities. As a result potential for wide dissemination is enhanced.

Figure 3 Diesel/Hydro Cost Comparison: Nepal

	US$ Diesel	US$ Hydro
Total Capital Cost Per Installed kW	500	1,500
Annual Cost of Capital Per kW @ 15% (Diesel Over 10 Yrs, Hydro Over 20 Yrs)	100	240
Annual Operation & Maintenance Cost/kW (Diesel 2%, Hydro 3%)	10	45
Total Annual Costs (Less Fuel)	110	285
Annual Fuel Cost/kW @ 30% Load Factor (Rs 7/Litre = US 0.35/Litre = US 0.14/kWh	368	--
Total Annual Costs @ 30% Load Factor	478	285
Cost Per kWh @ 30% Load Factor	0.18	0.11

Note: See also graph in Appendix 2.

Source: Computed from Agricultural Development Bank of Nepal figures (1987).

For micro-hydro installations to be cost-effective and sustainable a high level of local participation was required at all stages. The availability of a local institution involved in the appraisal and financing of micro-hydro schemes has been a major factor in the spread of micro-hydro in Nepal. Furthermore, the ability of local manufacturers to produce and repair both cheap, effective turbines and end-use technologies, to survey potential micro-hydro sites and to carry out installation without recourse to external assistance allows the installation of plants that are both locally appropriate and inexpensive.

The role of external agencies has altered from one of technology transfer and the funding of pilot projects to provision of training in less locally familiar aspects of micro-hydro such as electronic load control and hydrology.

In Nepal, where manufacture and use of turbines is now well established, training in such areas seems likely to remain the main area of external agency involvement.

(b) SRI LANKA

Like Nepal, Sri Lanka has a long tradition of water control - principally for irrigation. More recently (since the turn of the century) tea and rubber estates have used micro-hydro power and three turbine manufacturers operated in Sri Lanka during the 1940s and 50s. Some present day tea estates - now mostly nationalised - still use micro-hydro units installed over 50 years ago. Others are re-activating their micro-hydro capacity in response to the high costs of thermal and large hydro power from the grid. Some new plants are also being installed.

As in the case of Nepal, strong local demand for low-cost power which could be integrated into the local system of water management - in this case cash-crop irrigation - enabled micro-hydro to become re-established. Institutional involvement in plant management and finance also provided a sustainable basis for the adoption of micro-hydro on Sri Lankan Estates.

Micro-hydro is now an important source of power for many Sri Lankan estates. Why is this and how did it happen?

Project Identification

As interest in micro-hydro returned, enquiries from tea factories led the tea estate corporations to seek rehabilitation of their turbine plants. Some pilot projects were undertaken, one involving co-operation between ITDG and a Sri Lankan firm of contractors in the installation of a load controller and two turbines on a pilot project basis. Rehabilitation of estate micro-hydro plants was also undertaken.

As the technology became re-established a means was sought to bring its benefits to the rural poor. The Dutch-funded Integrated Rural Development Programme (IRDP) developed a system whereby electricity cost savings (over the grid alternative) accruing to estates using recommissioned micro-hydro plants are used for welfare projects for the notoriously poor estate workers. ITDG's technical expertise in micro-hydro was called on to co-operate in recommissioning installations on estates participating in the scheme.

A period of action research and feedback via continuous monitoring of performance, economic analysis and estate accounts followed. During this time not only were numerous surveys completed but also extensive on-site training of technicians, engineers, operators and mechanics was carried out.

Establishment

Interest in micro-hydro was based on potential savings from using micro-hydro electricity to complement the use of (more expensive) grid electricity. Current grid costs are 2.2-2.3 Sri Lankan Rupees (US$0.07) per kilowatt hour and are expected to increase over time. Diesel-powered generators have been installed on several estates but are only used as back-up due to high running costs (especially fuel). Micro-hydro, on the other hand, allows generation of electricity at less than Rs 2 kWh during a five year payback, and at approximately Rs 0.05 kWh thereafter on the basis of operation and maintenance costs. One example of the savings that can be achieved is the case of Seetha Eliya. On this tea estate diesel-powered generators could only be run at 50% capacity due to the cost of fuel. The installation of micro-hydro allowed the generation of 60kW while saving Rs30,000/month on fuel costs alone (1985 figures). Connection to grid supply at (Rs800,000), while cheaper than micro-hydro installation (Rs1.85 million), was felt by the estate to be less advantageous than micro-hydro [16].

As in the case of Nepal, cost reductions have been achieved via emphasis on training programmes in order to localise all aspects of projects. Some turbines were imported in the early stages, but - with increasing levels of skill among local engineers and technicians - existing turbines were rebuilt and local costs averaged 70% of rehabilitation costs. Imported items were alternators, high pressure valves, load controllers, switches and contactors. Costs have ranged from US$930 per kW to US$2,800 per kW according to the location and status of existing installations. Tea estate load factors are typically 30-50% and generally both steady and predictable.

Figure 4. Typical Capital Costs of Micro-Hydro: Sri Lanka

Scheme	Total K Cost	Cost/kW	Ann Op Cost	Ann Rev	Payback (yrs)	IRR (%)
Uda Radella	341,900	11,400 (456)	12,500	130,000	2.9	39
Gonapitiya	204,000	6,800 (272)	12,500	64,000	4.9	27
Labookellie	2,788,000	29,300 (1,172)	50,000	500,000	6.2	15

Notes: Figures in brackets are US$. Conversion rate: US$ = Rs 25

These are rehabilitation projects

Uda Radella and Gonapitiya use rebuilt turbines and penstocks

Labookellie has new penstock, turbine, alternator, control gear and transmission line

Compiled from IRDP Nuwara Eliya figures.

Financing of rehabilitation schemes came initially from the Dutch-funded Integrated Rural Development Programme (IRDP). Other donors have now also become involved. Such initiatives, including a World Bank funded scheme and several private sector schemes, have added to the profile of micro-hydro. At the time of writing, there are firm plans for 60 schemes to be rehabilitated using funds from the British Government, IRDP/Asian Development Bank and the Sri Lankan Estate Sector.

Scheme management is well-defined and experienced, particularly since training programmes have allowed the addition of hydro engineers to estate staffs. Welfare projects in the areas of water supply, sanitation, infrastructural improvement (including medical services) and agricultural programmes have been funded with scheme revenues.

Formal training courses for hydro engineers covering both technical and economic aspects of micro-hydro have been undertaken recently and ITDG is assisting a local engineering company to establish a small team trained to carry out site surveys and to manufacture low-cost turbines locally.

Turbine manufacture is now re-starting in Sri Lanka (after a 30 year lapse) as a demonstration and training project. This externally funded input will build local confidence and skills and erode the present disposition to import turbines rather than produce them locally.

Conclusion

Institutional demand has been the basis for the re-establishment of micro-hydro in Sri Lanka. It is based on the financial viability of micro-hydro, the productive use of power generated and the integration of micro-hydro into existing systems of water use.

The main areas for external agency involvement are the training of local manufacturers in site survey techniques, technology choice, economic appraisal and the fabrication of low-cost local turbine sets.

(c) PERU

Vertical axis watermills (very similar to those in Nepal) have been used in Peru since their introduction by the Spanish in the sixteenth century and control of water by means of diversion channels was well-established pre-conquest. In more recent times interest has been growing in the potential of micro-hydro technology.

Why is this?

Remote areas of Peru, given the difficult terrain and distances involved, require very high expenditure on transmission lines for connection to the national grid [10]. Furthermore, compared to Sri Lanka for example, scattered population and low load factors make grid connection uneconomic for large areas of the country. Although micro-hydro plants exist in Peru many communities have adopted diesel-powered machinery as an energy source. However, despite the current (artificially maintained) low price of diesel, major problems of reliability, repair and access to spare parts have made diesel-powered equipment an expensive and unsatisfactory source of energy in many areas.

Project Identification

In response to the demand for low-cost, reliable energy both the Peruvian government and some non-government organisations (NGOs) have become involved in micro-hydro programmes. Sample figures for installations of which ITDG has experience are:

	K Cost (US$)	Cost/kW (US$)	kW
Monte Salvado	80,400	1,340	60
Palomar	16,900	1,300	13
Pisha	10,000	2,000	5
San Marcos	10,000	2,000	5

Electroperu, the state electricity board, has spent large amounts on rural electrification projects (up to US$3-4,000 per household connected) including some small and micro-hydro installations. However in many cases a cheaper supply has recently been made available via individual and community installation, ownership and management of schemes. What are the reasons for this?

A study carried out in 1986 to evaluate government-installed micro-hydro plants [24] found that scheme failures were due to:

i) Load factors based on demand for domestic power rather than productive end-uses.

ii) Non-involvement of the local community (with consequent poor management and lack of commitment to maintenance)

iii) High running costs due to overmanned installations and artificially high salaries paid to staff.

Private and Community schemes on the other hand, have been based on:

i) Load factors based on productive end-uses as well as domestic requirements

ii) Locally identified demand for (or existence of) productive end-uses.

iii) Cost reductions from installation, operation and management by the community concerned rather than by salaried employees.

Establishment

ITDG's involvement in Peruvian micro-hydro dates from 1984 and is relatively recent compared to programmes in Nepal and Sri Lanka. Engineers skilled in work on large hydro schemes are available in Peru. However, most lack experience in the design and construction of smaller schemes, micro-catchment survey techniques, and technologies such as ELCs and multi-jet Pelton turbines. In respose to requests from local organisations a programme of technology transfer and training was undertaken.

A turbine (driving workshop and agro-processing equipment) was installed at Monte Salvado during 1987 and commissioned earlier this year as a demonstration project. Two manufacturers, as well as a counterpart engineer, have been trained in improved turbine production and site survey techniques. In order to encourage broad-based approaches to project design two irrigation engineers from local NGOs have also been trained in site survey techniques. Finally, courses on site surveying and end-use assessment - including methods adapted to local micro-catchment analysis - have been run for village-based extension workers (promotores).

Localisation

Participation by local communities and manufacturers in all aspects of micro-hydro projects generate a number of local benefits. First, locally manufactured turbines cost approximately one-third of imported equivalents. Second, imported turbines may not be available to communities or individuals lacking access to foreign exchange. Third, the localisation of skills brings similar benefits in terms of both reduction and localisation of costs. Finally, by involving project end-users at all stages, appropriate project designs can be achieved which fit into existing water and energy systems and community priorities.

Whereas in Nepal and Sri Lanka sources of credit or funding and micro-hydro users have co-operated closely, this is not so evident in Peru. NGOs who might become involved in micro-hydro programmes have not, as yet, tapped all sources of funding. To raise local awareness of these issues ITDG is organising a Rural Energy Seminar in Cusco (Peru) in August this year

Conclusions

High micro-hydro potential, combined with high levels of local demand for energy in Peru [5] and the potential for productive end-uses in agro-processing (eg coffee and cocoa), provide a strong background for future micro-hydro programmes. Given the expanding local capability in all aspects of micro-hydro, it seems likely that individually and community owned micro-hydro installations will increase in Peru. Such expansion is based on both economic justification of the technology and the upgrading of local ability to make, install and manage it. External inputs of training in the areas outlined above and of funding for pilot schemes will assist this process.

PART 3 CONCLUSION

Issues of project cost and local sustainability have been central to this paper. The three case studies considered show that schemes based on cost minimisation and productive end-uses for hydro-power can become not only self-supporting but profitable. The key ingredients of cost-effective power in each case have been:

- Financial viability
- Localisation of technical skills and processes
- Integration of micro-hydro into local institutions and systems (in particular systems of water management)
- Training and pilot funding from external agencies
- Sufficient national potential for micro-hydro to justify development of local manufacturing capability

Financial viability has been dependent on:

a) Adequate load factors or demand based on productive end-uses of power;

b) Low-cost equipment based on local design and manufacture of components;

c) Low-cost survey, design, installation and management of projects by upgrading of local skills and the involvement of local communities, engineers and manufacturers.

What does this tell us concerning the roles of manufacturers and development organisations both in developed and developing countries?

1) Developed Country Manufacturers

    1) Technology transfer

    2) Training of local manufacturers, installers and operators

2) Developing Country Manufacturers

    1) Establishment of local ability to manufacture and/or repair penstocks, turbines etc where adequate demand exists

    2) Establishment of local ability to manufacture and/or repair end-use equipment where adequate demand exists

3) Development Organisations (Local and External)

    1) Pilot/demonstration projects

    2) Dissemination of proven appropriate technologies

    3) Institution building

In practical terms these roles involve training programmes in the following areas:

Technical:	Site surveys, installation, design and production of hydro and end-use machinery.
	Operation, maintenance and repair of micro-hydro plant and end-use equipment.
Techno-economic:	Identification, planning, implementation and management of schemes including end-uses.
Socio-economic:	Financial and economic appraisal, institutional assessment, systems analysis, monitoring and evaluation of projects.

Local organisations, manufacturers and institutions are, by virtue of their location, best placed to assist in the local development of micro-hydro programmes. The central role of external agencies and manufacturers is, therefore, to enable these groups to localise both the technologies and the capabilities that are required for sustainable micro-hydro programmes. Technology transfer and external funding are required, but the most important aspect of this process is appropriate training for developing country engineers, economists and communities.

Appendix 1: The Cost of Micro-Hydro

Nepal	Cost/kW	kW	
Manbhak	1,024	7.5	[7]
Turture	1,163	8.0	[7]
Eyanja	1,430	100	[28]
Sri Lanka	**Cost/kW**	**kW**	
Labookellie	1,172	95	See note (iv)
Seetha Eliya	1,650	62	ITDG Records
Dunsinane	803	160	See note (iv)
Peru	**Cost/kW**	**kW**	
Monte Salvado	1,340	60	ITDG Records
Palomar	1,300	13	See note (v)
Pisha	2,000	5	See note (vi)
San Marcos	2,000	5	See note (vi)

Note:

(i) These schemes are new electricity generating schemes.

(ii) Costs include transmission lines.

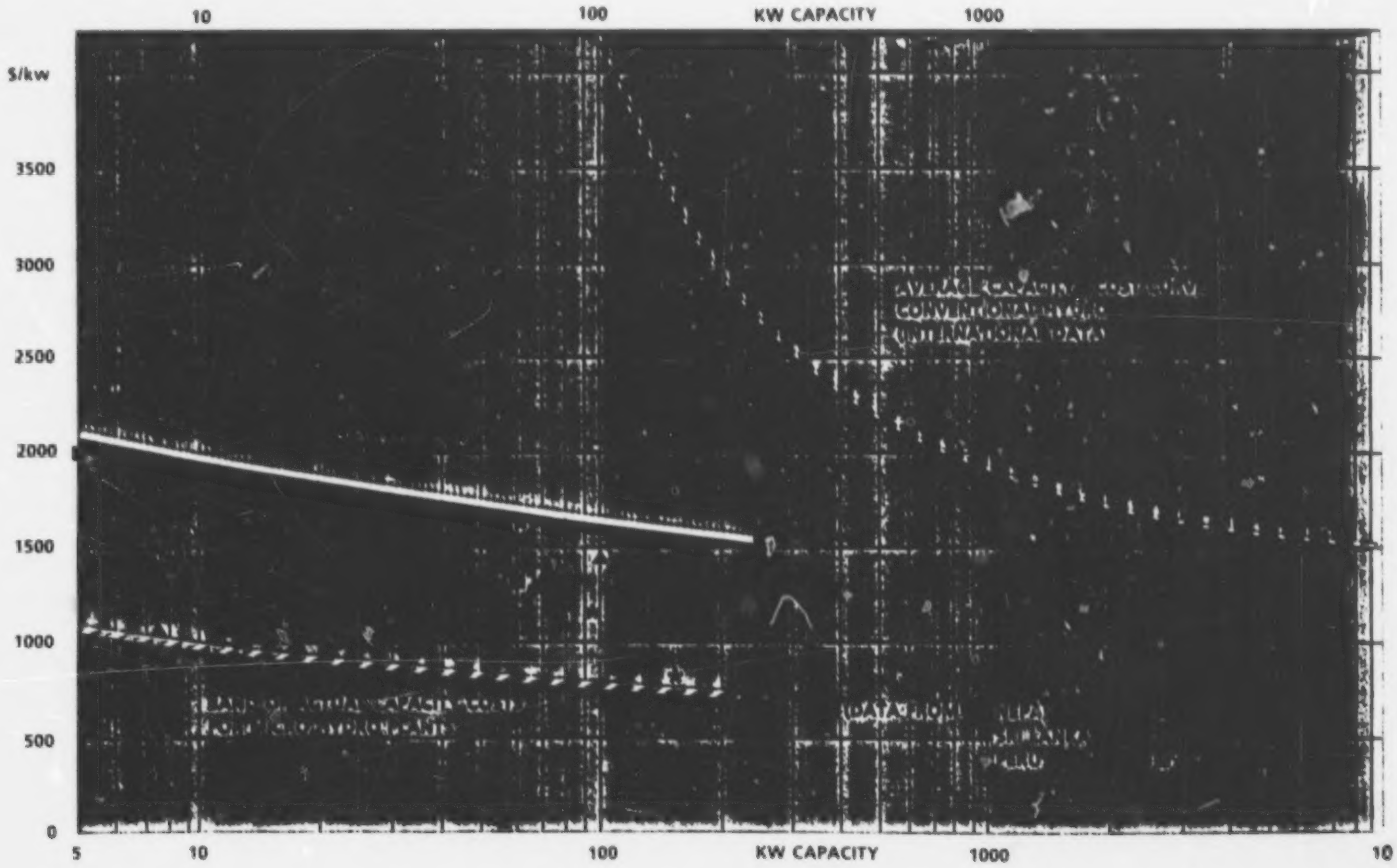
(iii) All Figures US$.

(iv) Wishart G. Micro-hydro programme, Nuwara Eliya IRDP. Progress report to end 1987. UK 1988.

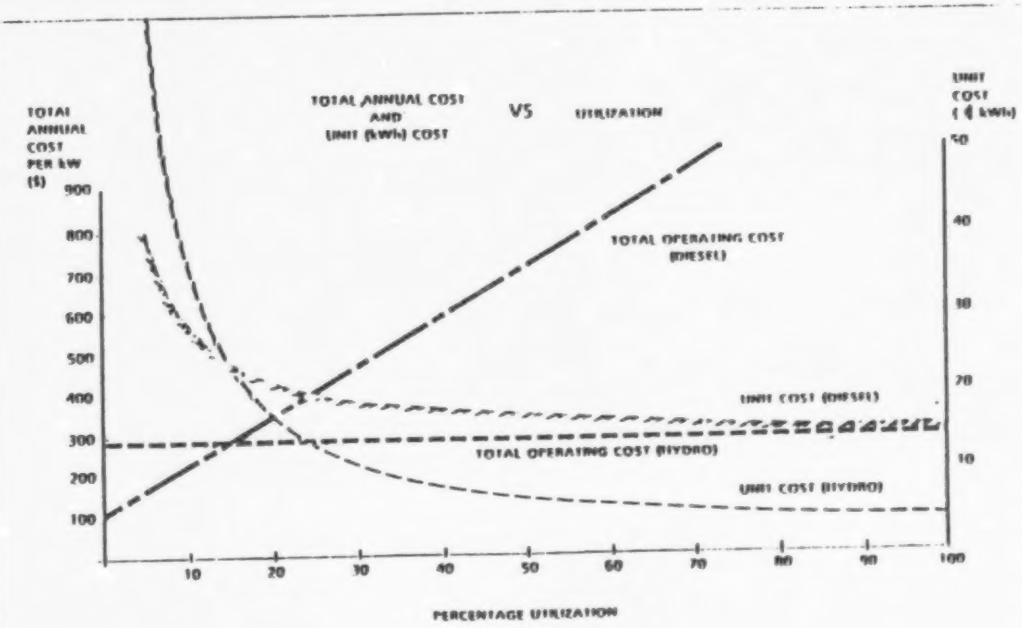
(v) Hydropower F E Ltd, Lima.

(vi) Diaconia Ltd, Lima.

Cost Data for Small and Micro-Hydro Electric Schemes



Appendix 2: Diesel/Micro-Hydro Cost Comparison



TOTAL ANNUAL COST = CAPITAL CHARGE (DEBT SERVICE) + OPERATING & MAINTENANCE COST.

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Build-Operate-Transfer Concept: A Case History from Turkey

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A PAPER PREPARED FOR
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BUILD-OPERATE-TRANSFER CONCEPT: A CASE HISTORY FROM TURKEY

Ernest A. Portfors, Josef Lampa and Ahmet Eltekin

If we go sufficiently far back in the history of mankind, we find that barter or trade by direct exchange of commodities or services without the use of currency was the basis of primitive economies. Then came the cowrie shells, gold and eventually money. During more recent times, it appears that the trend has reversed itself in modern international trade.

As many Latin American and African countries have limited resources of foreign exchange to pay for imports, they are turning more and more to counter trade, also called buy-back or offset. And the habit is spreading-not long ago Yugoslavia agreed to supply their Avia wine in exchange for a Coca Cola bottling plant and equipment.

Unfortunately, power stations, highways, tunnels and metro systems do not produce a physical return that can be used to pay a foreign builder for the supply of equipment and services. Benefits derived from a new metro cannot be readily exported. Electricity can be exported, but only within geographical limits which may not suit the international trade.

Turkey has recently found a solution to this problem called the Build-Operate-Transfer formula. This involves foreign entrepreneurs taking a share in a company established to build and operate a project. The entrepreneurs will be able to repatriate outstanding loan repayments, including their share of earnings from equity holdings. Once the loans have been repaid, the joint venture is dissolved and the ownership of the facility is transferred to the host government or public utility which continues its operation. Hence the term "Build-Operate-Transfer". The formula is an ingenious system, as the host country cannot lose: with zero costs, any benefits will result in an infinite benefit/cost ratio.

The publication "Regulation on Determining the Principles for Granting Permission to Institutions other than the Turkish Electricity Authority for the Construction and Operation of Electric Power Plants", published by the Turkish Ministry of Energy and Natural Resources in 1986, explains the system and sets out the rules.

If the host country cannot lose, the foreign investor certainly can, for a number of reasons, political and technical. In investing money in a BOT project in Turkey, the investor is accepting that contract as negotiated will be honored by the present government and any governments to follow throughout the life of the project. That in turn guarantees that all electrical energy generated by the project will be purchased at stipulated prices, and because the prices were calculated on the basis of 15% equity investment and a 15% net return on equity (both directly dictated by BOT guidelines), that is exactly what the investor will get over the life of the contract. Assuming, of course, that the Turkish lira remains freely convertible to U.S. dollars and that no restrictions are placed on repatriation of U.S. dollars from Turkey.

The usual technical risks with hydro development are also present, and some of these are described in the following case history.

The Tortum 2 hydroelectric project is located in northeastern Turkey, very close to the Russian and Iranian borders (Figure 1).

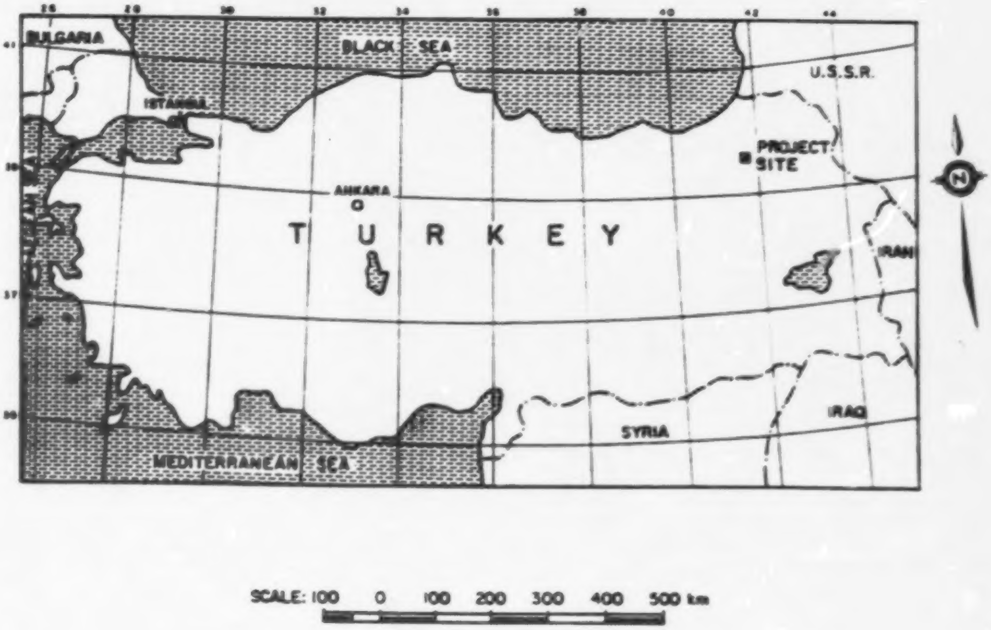
BULGARIA
BLACK SEA
ISTANBUL
U.S.S.R.
PROJECT SITE
ANKARA
T U R K E Y
IRAN
SYRIA
IRAQ
MEDITERRANEAN SEA
N
SCALE: 100 0 100 200 300 400 500 km

FIG. I - LOCATION PLAN

When Klohn Leonoff (with assistance from B.C. Hydro International) became involved, a Turkish feasibility study had already been completed under the direction of NUR-TEK A.S. of Ankara. The project will utilize a stretch of the Tortum River immediately downstream of the existing Tortum 1 power plant (Figure 2). The previous arrangement had a conventional diversion weir and intake in a gorge, and required a diversion tunnel. The power conduit consisted of a fully concrete lined 3.6 m Ø free-flow tunnel, underground headpond with spillway and silt ejection galleries, free-standing steel penstock in a shaft and on surface, surface powerhouse on deep pervious alluvium and a long tailrace channel excavated in the same material. Approximately 87 m of head was developed, which combined with 25 m^3/s flow, produced 18 MW of power.

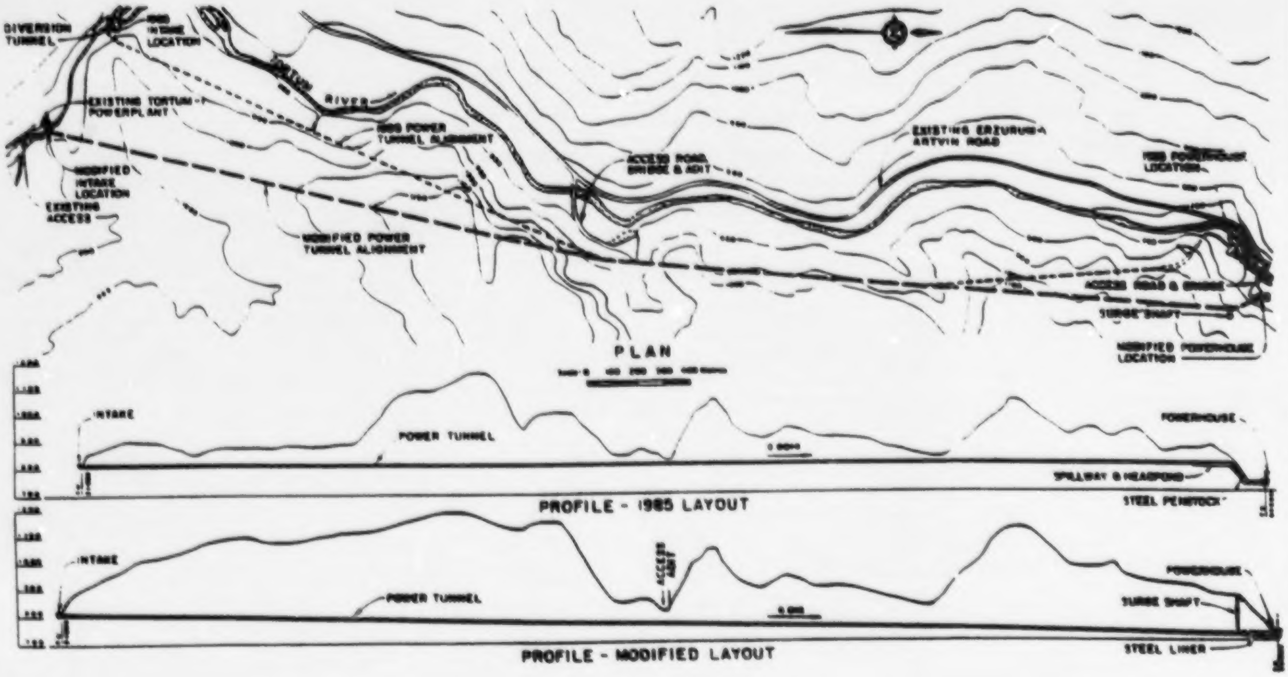
DIVERSION TUNNEL
1985 INTAKE LOCATION
EXISTING TORTUM POWERPLANT
River
1985 POWER TUNNEL ALIGNMENT
MODIFIED INTAKE LOCATION
EXISTING ACCESS
MODIFIED POWER TUNNEL ALIGNMENT
ACCESS ROAD BRIDGE & ADIT
EXISTING ERZURUM-ARTVIN ROAD
1985 POWERHOUSE LOCATION
ACCESS ROAD & BRIDGE
SURGE SHAFT
MODIFIED POWERHOUSE LOCATION
PLAN
INTAKE
POWER TUNNEL
POWERHOUSE
SPILLWAY & HEADPOND
PROFILE - 1985 LAYOUT
STEEL PENSTOCK
INTAKE
POWER TUNNEL
ACCESS ADIT
POWERHOUSE
SURGE SHAFT
PROFILE - MODIFIED LAYOUT
STEEL LINER

FIG. 2 - PLAN AND PROFILES

During our feasibility study, several improvements have been implemented:

- intake was relocated close to the existing powerhouse, which eliminated the need for the diversion tunnel;
- power tunnel was pressurized, which simplified operation, eliminated headpond and galleries. Also eliminated was the liner, as the local limestone is considered sufficiently competent and tight;
- powerhouse was relocated into a rock ridge, eliminating the foundation problems, surface penstock and tailrace dredging.

Figure 3 shows the downstream end of the conduit as originally conceived. Figure 4 shows the same after the improvements.

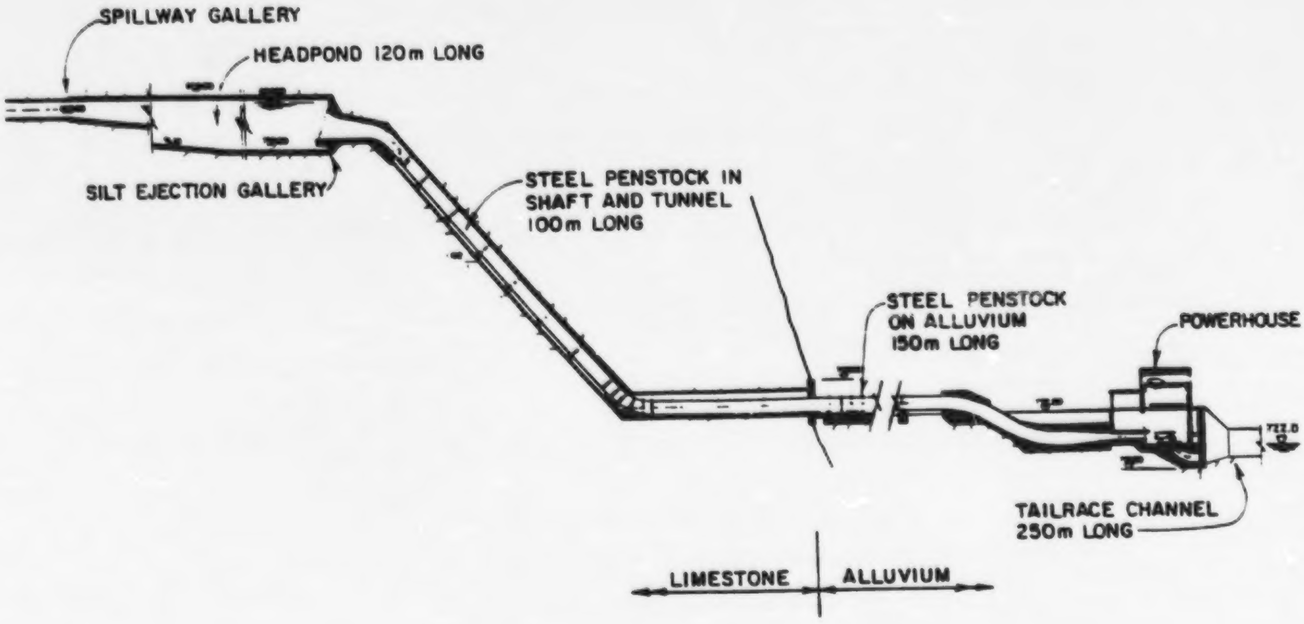
SPILLWAY GALLERY
HEADPOND 120m LONG
SILT EJECTION GALLERY
STEEL PENSTOCK IN SHAFT AND TUNNEL 100m LONG
STEEL PENSTOCK ON ALLUVIUM 150m LONG
POWERHOUSE
722.0
TAILRACE CHANNEL 250m LONG
LIMESTONE
ALLUVIUM

FIG. 3 - 1985 PROFILE

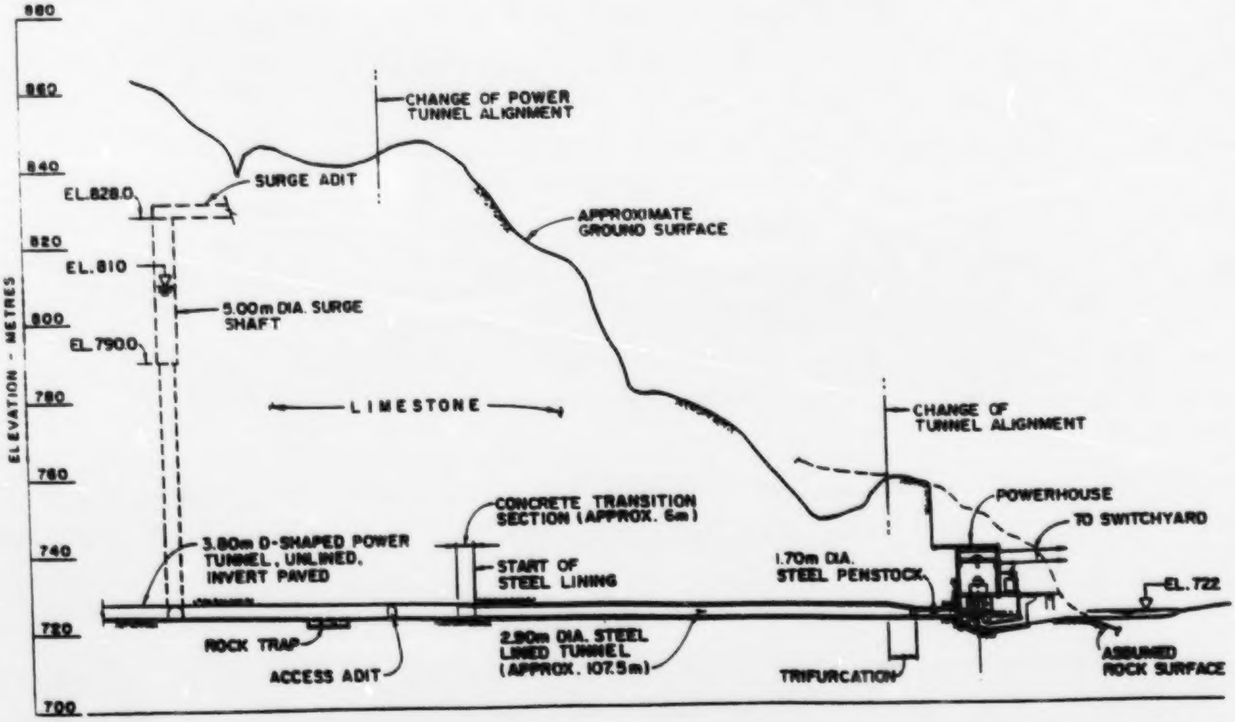
880
860
840
820
800
780
760
740
720
700
ELEVATION - METRES
CHANGE OF POWER TUNNEL ALIGNMENT
SURGE ADIT
EL.828.0
APPROXIMATE GROUND SURFACE
EL.810
5.00m DIA. SURGE SHAFT
EL.790.0
LIMESTONE
CHANGE OF TUNNEL ALIGNMENT
POWERHOUSE
TO SWITCHYARD
CONCRETE TRANSITION SECTION (APPROX. 6m)
3.80m D-SHAPED POWER TUNNEL, UNLINED, INVERT PAVED
START OF STEEL LINING
1.70m DIA. STEEL PENSTOCK
EL.722
ROCK TRAP
ACCESS ADIT
2.90m DIA. STEEL LINED TUNNEL (APPROX. 107.5m)
TRIFURCATION
ASSUMED ROCK SURFACE

FIG. 4 - MODIFIED PROFILE

Furthermore, the installed capacity has been reduced from 18 to 11 MW, with two 5.5 MW vertical shaft Francis units. This maximized return on investment, as the third unit in the 18 MW scheme was very seldom used (capacity factor about 35%). However, minimum provisions have been incorporated in the powerhouse for the third unit and the tunnel is sized such that it can be readily improved in the future, if TEK desire, to accommodate the third unit.

The following assumptions have been made in the financial analysis:

- two years of construction, 1989-1990
- 10 years of loan repayment, 1991-2000
- 8.5% interest on loan capital
- loan IDC capitalized at completion of construction
- blended annual principal and interest payments on loan
- equity participation equals 15% of total investment
- five years of equity repayment, 2001-2005
- 15% return on equity capital
- equity principal paid in equal installments
- equity IDC capitalized at completion of construction
- capital and O&M costs inflating at 4% per annum, US $ terms
- amortization rates as used in the BOT program
- 10.3% and 5.0% withholding taxes
- exemption from other corporate taxes
- estimated project costs of US $11.2 million ('87)
- average annual delivered generation of 51.0 GWh
- transfer of project to TEK in 2006

Based on these assumptions, the required selling prices fluctuate between 5.9 and 2.7 cents/kWh, with the average over the 15 year BOT period of 4.6 cents/kWh.

As these prices are slightly below the TEK average selling prices in 1991 (differential about 1.5 cent/kWh), very much below by 2005 (about 8.5

cents/kWh) and even more so by 2015 (about 14 cents/kWh), TEK will make a profit on Tortum 2 power every year. Unfortunately, it is not until approximately the year 2000 that the required selling price falls below the BOT guidelines stipulated upper limit of 60% of TEK selling price. At this moment we do not know what the TEK's production costs or avoided costs are and how this will be accepted by the Turkish Ministry of Energy and Natural Resources, to whom the completed feasibility report has been submitted for approval before contract negotiations can start. On the plus side, the project is located in a remote part of the country which is receiving increased attention from the government. On the minus side, although there are many BOT projects planned in Turkey, very few BOT contracts have been successfully negotiated, and even fewer implemented.

Why then is it that so many are interested in Turkey? Where else in the world today are there 74 major dams and powerhouses under construction at the same time only to be absorbed by the fast growing demand in the next seven years? In which other country 20,000 MW of additional installed capacity will be required by the beginning of the next century? Where else can hydraulic resources be found to provide such capacity? The answer to all three questions: Only in Turkey.

OTHER AGENCIES:

The conference was hosted by the Ontario Ministry of Energy, in co-operation with a number of national and international development agencies:

Canadian International Development Agency
Energy Mines and Resources Canada
National Rural Electrification Cooperative Association
Idaho National Laboratory
United Nations Department of Technical Co-Operation for Development
Federal Energy Regulatory Commission

Ontario
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